STATISTICAL ANALYSIS AND DYNAMIC VISUALIZATION OF TRAVIS PEAK PRODUCTION IN THE EASTERN TEXAS BASIN

A Thesis

by

BABAFEMI O. AYANBULE

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

August 2010

Major Subject: Petroleum Engineering

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Production in the Eastern Texas Basin

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Approved by:

Chair of Committee,	Peter Valko
Committee Members,	Maria Barrufet
	Charles Glover
Head of Department	Stephen A. Holditch

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ABSTRACT

Statistical Analysis and Dynamic Visualization of Travis Peak Production in the Eastern Texas Basin. (August 2010)

Babafemi O. Ayanbule B. S., Colorado School of Mines, Golden CO

Chair of Advisory Committee: Dr. Peter Valko

Gas production has increased exponentially over the last 30 years, which is in response to the increasing demand for natural gas. This trend is speculated to continue to increase as legislation continues to be passed requiring power plants to reduce nitrogen oxide emissions. This recently happened in Colorado according to the Washington Post, giving more consideration to using natural gas.

As natural gas becomes more popular there is a need to understand the production patterns and observable trends, integrating data from various sources. This research will attempt to do just that for wells producing from the Travis Peak formation.

Using data from HPDI L.L.C., (www.hpdi.com) a visual representation was created for the areal distribution of peak gas rates and cumulative gas production. This allowed us to categorize wells by their production performance and we found that areas with relatively high peak gas rates also had high cumulative gas production.

An analysis of these wells was done by completion year, and we found that wellhead prices of natural gas strongly influenced the annual number of new wells. We also found that the distribution of the annual number of new wells affected the average annual initial production rate and the peak gas rate of new wells.

Wells located in areas of poor production performance were analyzed and it was apparent that newer wells performed relatively better than older ones and well stimulation is a major requirement for better gas production.

Wells located in areas of good production performance were also analyzed and we found that the distribution of newer wells to older ones influenced the relative performance of individual wells.

Overall, there was no observable trend between production variables in Travis Peak. No trend in production variable was found to be exclusively associated with good performing wells or poor performing wells.

DEDICATION

This thesis is dedicated to God for his continuous blessings, my parents Mr. and Mrs. M. Ayanbule for their unconditional love and support, and my siblings for being my role models.

ACKNOWLEDGEMENTS

I thank my committee chair, Dr. Peter Valko, for taking me on as his student and for his guidance during this research.

I thank Dr. Maria Barrufet for her efforts which resulted in my acceptance into the master’s program in the Petroleum Engineering Department at Texas A&M and for agreeing to be on my committee.

I also want to thank Dr. Charles Glover for agreeing to be a member of my committee; and finally I would like to thank my friends for their endless words of encouragement during this process.

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1 INTRODUCTION

1.1 Background and Literature Review

1.1.1 Background and Literature Review on Travis Peak

The Travis Peak formation is an arc shaped terrigenous clastics that spans from east Texas through southern Arkansas and northern Louisiana into southern Mississippi (Saucier, Finley et al. 1985). The formation is a low permeability gas producing sandstone that is said to have 19.8 to 24.7 Tcf of gas-in-place in Texas alone according to Saucier et al, and this will be the focus on this research.

According to the Energy Information Administration, 90% of the gas consumed in the United States in 2007 was produced domestically and 31% of this domestic gas production was produced from the state of Texas, the production share of other states is shown in Figure 1.1.

This thesis follows the style of *SPE Journal.*

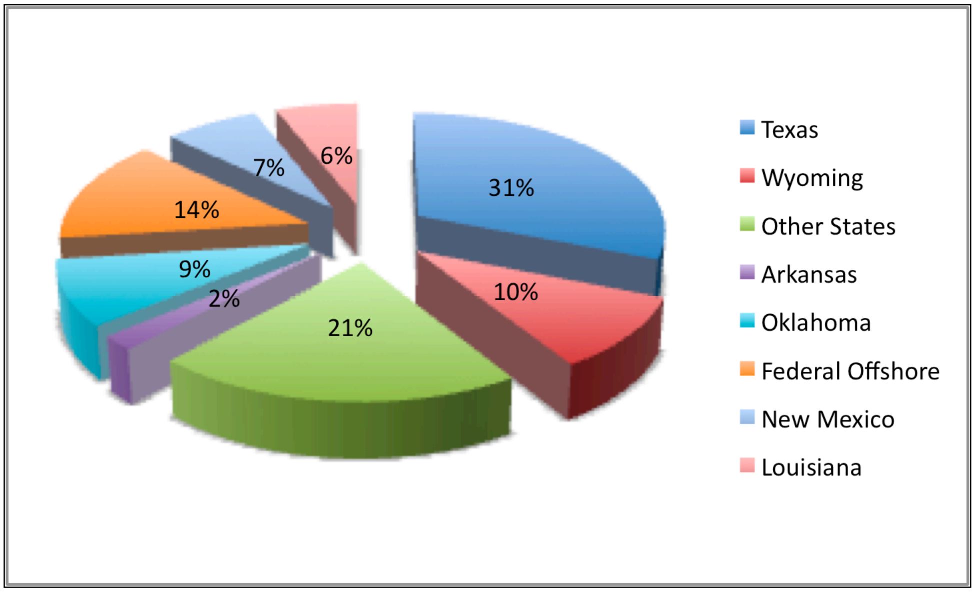

Figure 1.1- U.S. domestic gas production by state (Energy Information Admin. 2008)

A contributor to the production statistic shown above is Travis Peak, which covers 30 counties in the eastern Texas Basin with just over 4800 production wells. Figure 1.2 shows a map of producing fields from the Travis Peak formation in the northeastern part of Texas into the northwestern part of Louisiana.

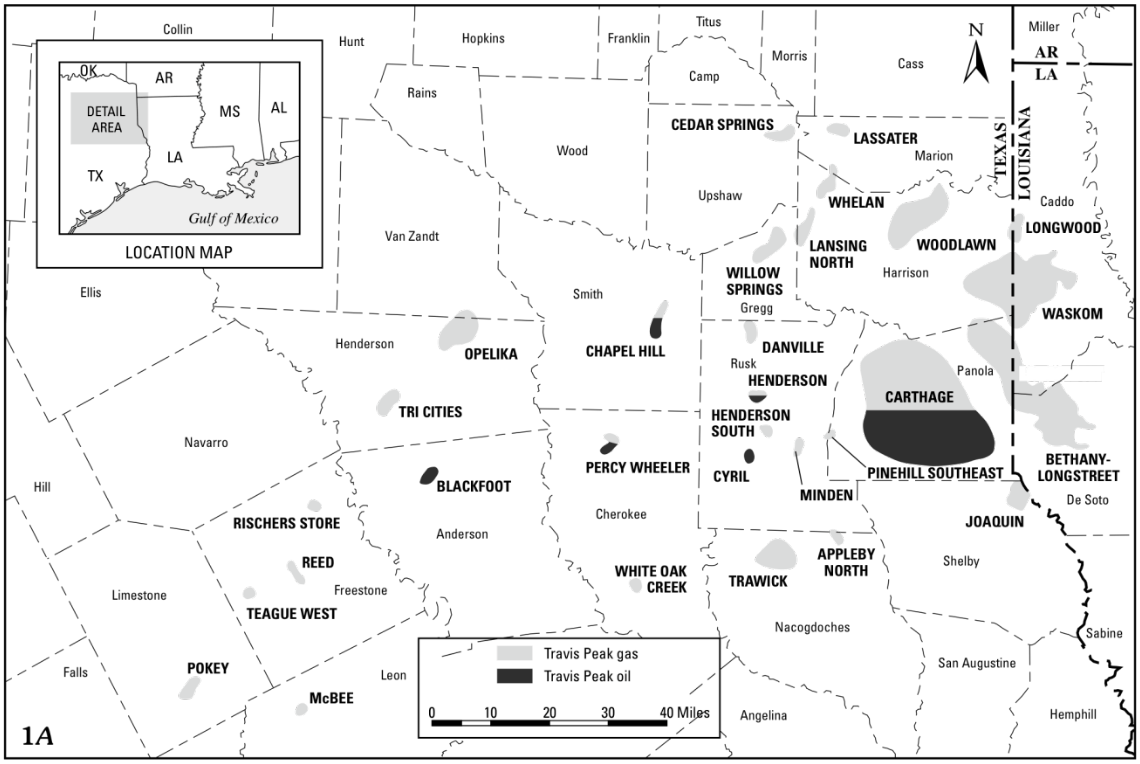

Figure 1.2- Map of northeastern Texas showing major fields that have produced hydrocarbons from Travis Peak (Bartberger, Dyman, et al. 2003)

Dutton and Diggs studied the evolution of the porosity and permeability of this formation in 1992, where they discussed the depositional environment and different diagenetic processes-mainly a combination of the variation in detrital mineralogy in the sandstone, and modification by compaction and cementation during the burial process- that influence both reservoir properties (Dutton and Diggs 1992). This produced a redbed-bearing sequence of fine to coarse-grained sandstone, siltstone, mudstone and shale (Syfan and Robinson 1993). Dutton et al. found that both porosity and permeability are not uniform throughout the formation but generally decrease with increasing burial depth. In particular, the permeability of this formation decreases by four orders of magnitude when going from a depth of 6,000ft to 10,000ft (Bartberger, Dyman, et al. 2003) .

Syfan et al. stated that the formation thickness ranges from 1,425 ft to 3,190 ft with a general increasing trend going toward the southeast from the northwest part of the area.

Further review of literature provided insight into the past applications of statistical analysis in industry. Some focused on the reservoir studied in this research (Travis Peak), and the observed trends in this case be used as in our assessment. Others focused on different reservoirs; however, the application techniques used will be adopted.

1.1.2 Literature Review on Statistical Applications

In 1991, Holditch et al. applied statistics to estimate averaged tight gas reservoir properties from the Travis Peak formation that was used to accurately predict well performance. A distribution of reservoir permeabilities, porosities and net pay thickness was obtained and interpreted statistically.

They applied the theory proposed by Rollins et al. in 1989 that states that natural resources are distributed log-normally and that the median value from this distribution is a more accurate representation of the averaged reservoir properties such as permeability; "the distribution of permeability in a formation can be generally characterized as unimodal, right skewed, and similar to a log-normal distribution" (Holditch, Lin, et al. 1991).

Data from the Texas Railroad Commission supplied by Texas Oil and Gas Plc. (TXO) for 561 wells and the Bureau of Economic Geology for 191 wells in Travis Peak was analyzed to show that the distribution of permeability was unimodal and skewed, similar to a lognormal distribution (Holditch, Lin, et al. 1991). They also found that permeability and porosity highly correlated where they have a strong positive relationship; implying that as permeability increases, porosity tends to increase (Cline 2009 (a)). In the case of net pay thickness, they found that it was inversely related to permeability, implying that areas with large net pay thickness, permeability will be low.

They computed the cumulative probability densities for both data sets where the median value of permeability was used to estimate average gas recovery per well and compared to the recovery obtained from that arithmetic mean and different assumptions for fracture lengths - no fracture and 500ft - and drainage area-160 and 640 Acres.

The predicted gas production for the unfractured well in a reservoir with the smaller drainage area was just above the actual value in the case where the median permeability was used and much higher when the arithmetic mean permeability was used. For the unfractured well with the larger drainage area, the predicted gas production was lower than actual when the median permeability was used and higher by a factor of 2 when the arithmetic mean was used. The recovery estimated from a fractured well in the smaller reservoir matched the actual value for both cases where the median and arithmetic mean permeability values where used.

They found that the median value of permeability is the most accurate value that can be used in estimating ultimate recovery of a tight gas reservoir, which was one of their main conclusions.

Awoleke and Lane used descriptive statistical analysis to evaluate gas production with respect to water production using data from HPDI L.L.C. for the Barnett Shale play in the Fort Worth basin. Evaluated data from 11,000 completions, splitting them into core county areas with a limestone barrier between formation and water layer-and non-core-areas where water layers lie directly below formation.

The core and non-core counties were compared by looking at the distribution of wells and found that horizontal wells were most common in the non-core and core areas but closer to the number of vertical wells than in the case of the non-core areas.

He then looked at the number of different well type as a function of time in two different counties and found that despite the distribution of wells noted initially, there was an apparent drop in the number of vertical wells while the number of horizontal wells rose and was presently the most popular choice. This served as the basis of his study on horizontal wells.

He looked at the average water and gas production from horizontal and vertical wells in each of the core and non-core areas, and found that minimal water was produced from horizontal wells in the non-core area and better average gas was produced from wells in the core areas; suggesting that location of wells is a key predictor in productivity in Barnett Shale.

He attempted to answer the question of which factor is the most important predictor of gas productivity in Barnett Shale from completion time, that is a crucial factor because of the improvements in hydraulic fracturing technology, to well location. He looked at two counties in the core area and compared the annual average gas production in both cases. It was apparent that the gas production corresponding to the highest producing year in one county was the lowest production year in the other county implying that location is a better predictor of gas productivity versus time (Awoleke and Lane 2010).

He also looked at the average annual water production for both counties and found a decreasing trend in both cases, stated three possible reasons - reduction in fracture fluid volume, increase in fracture fluid retention by rock or the contained propagation of induced fracture to the underlying formation.

Jong and Baker et al. in 2009 applied empirical statistical analysis in part with common water-flood surveillance techniques and analytical methods using only production data to understand the communication between injector and producer wells and ultimately to create a fluid flow model of the reservoir.

This analysis was applied to two reservoirs - Alderson Upper Mannville D and Jenner Upper Mannville E Pools - where two pairs of wells were chosen from both reservoirs and analyzed. In the Anderson Pool, well pair 1 was found to have a better communication than well pair 2. They confirmed this by looking at a plot of liquid production against water injection where a common average trend noted and that of pair 2 failed to show a similar average trend.

More graphical correlations between various variables and production data were done to find trends and compare observation for both well pairs. A plot of cumulative liquid production against cumulative water injected with supper imposed slopes of the curve showed that a unit slope that indicated good communication at early time after injection and a slope greater than one was noted at later time, indicating that the injector influencing the producer 5 years after injection (Jong, Baker et al. 2009).

In the Jenner Pool, they divided the pool into four different groups and then plotted the historic pressure profile with respect to time. They found a large scatter in pressure point after injection started and noted the high pressure points were evidence that some producer wells were getting pressure support from the injector wells and low pressure points indicated those producer wells not getting pressure support. Overall they noted a decrease in pressure at late time.

The same analysis that was done in Alderson was also completed here where the plot of cumulative liquid production against cumulative water injected showed a linear trend initially, that they attributed to good injector producer response; however, they noted a drastic change in curvature at late time indicating poor well communication. They justified this trend by the noted decrease in pressure profile at late time and correlated it to an increase in compressibility "and it is evidence that there is no correlation between injector and producer" (Jong, Baker et al. 2009). They attributed the poor communication to the low pressure in the system.

The strength of communication between injector and producer wells was measured by the production rate response to injection rate. They developed three types of communication strengths based on a general trend of how well the curve represented that of water injection. Good communication was hypothesized where they found a good representation by the production curve and limited communication strength was assumed where there was no relationship between the two curves.

The slope of cumulative liquid produced vs. cumulative water injected was also used to measure the communication strength between wells. They expected that the quantity of water injected should yield the same amount of liquid produced and the deviation of the slope will represent the strength in communication. They determined that good communication by an average slope greater than 15%, intermediate communication by an average slope of ±15% and poor communication by an average slope of less than 15%.

They concluded that these empirical techniques were useful in identifying possible trends, that the statistic of the connections can be assessed using classical surveillance methods.

Forth, Slevinsky, et al. in 1997 used statistics to identify the variables that influence the good reservoir performance using production data obtained from the Golden Lake's Waseca formation.

They applied multivariate analysis to identify correlations among several variables that include well location coordinates, wells status, completion date, net pay, average porosity, water saturation, perforation charge size, density, production history variables that vary with time and geological variables that they considered constant during the field life.

In this analysis, linear regression model was developed to model oil rate, water rate, water cut, recovery percentage and water-flood breakthrough. Their linear regression model contained only those independent variables with large regression coefficients, these they considered to be significant in predicting each of the dependent variables and a coefficient of determination (R-squared) was used to measures how well the model fit the data (Forth, Slevinsky, et al. 1997). The R-squared coefficient ranges from 0 to 1, 1 being a perfect model fit (Cline 2009 (a)).

A Studentized residual analysis was also applied to measure the variation between the values the model predicted and that observed from the data set (Forth, Slevinsky, et al. 1997). This is the difference between the model and predicted values – residuals - divided by the standard error of the residual values. These were used to categorize the studied wells into common groups.

Groups with studentized residuals less than negative one, greater than one and between negative and positive one were used to develop three different linear models, with improved R-squared coefficients.

Discriminant analysis from SAS/STAT© module was used to identify factors common to the wells in the three groups and of particular interest was finding the characteristics associated with wells that tend to be good performers, that is, those with high oil rates, low water cut, and high recovery factors. (Forth, Slevinsky, et al. 1997)

The probability of the wells being in the group of good performers was then determined and mapped on contour plots and they found a clear resemblance when compared with geological flow unit maps from seismic, log and core data.

A second order non-linear regression model was applied to further analyze the relationship between the significant independent variables – like perforation density and charge size - and the dependent variable - in the case of oil rate and they found the optimal charge size combined with maximizing the perforation density will achieve the full potential of a well. They correlated this to the near wellbore production mechanism for heavy oil in unconsolidated reservoirs. Table 1.1 below gives a summary of significant variables that are influential in predicting the five dependent variables modeled.

TABLE 1.1 SIGNIFICANT FACTORS THAT INFLUENCE FIVE PRODUCTION VARIABLES IN WASECA FORMATION

Oil Rate	Water Rate	Water-cut	Recovery Factor %	Breakthrough Time
Net Pay	Structural Elevation	Well Location	Water Saturation	Structural Elevation
Water Saturation	Well Location	Perforation Density	Porosity	Water Saturation
Well Location	Perforation Charge Size	Porosity	Perforation Charge Size	
Perforation Density	Porosity	Water Saturation	Oil Viscosity	

They were also able to determine how each independent variable related to the modeled – dependent - variable and explained the connection using engineering principles and existing conditions in the Golden Lake formation. For example, they were able to determine that water saturation was inversely correlated to oil rate and related this trend to the lower oil reserves being located where water saturation was higher.

Overall Forth, Slevinsky, Lee and Fedensczuk were able to identify the influential variables that impact the key performance variables listed in the above table and postulated that this will enhance the optimization of the Golden Lake Wacesa formation.

1.2 Research Objective

From the literature reviewed, it is clear that statistics has been used extensively to analyze reservoir properties, reservoir production as well as creating a prediction model for future production. In some cases it was applied to determine the relationship between specific production variables leading to important conclusions, in other cases a more extensive analysis of different production variables was conducted to determine which variables affect production. However, a visualization component that gives an areal distribution of production data, and relating this to well locations was missing.

The objective of this research is to develop a tool that can provide further insight into the factors affecting production performance in a given reservoir. In particular, we focus on two goals.

First is the dynamic visualization of production to identify good producing areas relative to other locations in the study area. The second part is to conduct statistical analysis of production data to determine the variables that are good predictors of well performance in a tight gas reservoir.

1.3 Thesis Outline

The following sections in this thesis will describe the data preparation and quality control phase, the statistical analysis procedures and the main conclusions.

Section 2 will outline the quality check of the data from HPDI. How the original data were scrubbed for erroneous values and how we eliminated such data from the analysis to minimize the possibility of a haphazard - where there is no means by which observations are reliable - analysis (Cline 2009 (b)). We will explain how subsets of data were created from the scrubbed data to allow for an easy versatile analysis based on different production variables.

Section 3 will show the steps taken to create the dynamic visualization of production data. We will explain how the module was created within the framework of software system Mathematica (by Wolfram Research) and how the additional services of the software were used in obtaining geographical data, supplementing the HPDI data. Then we will show how Travis Peak production was visualized while dynamically identifying each well.

Section 4 presents our analysis of production data. We will show how we identified the characteristics that are associated with those wells found to perform lower relative to the rest and those that performed relatively better.

Section 5 will present conclusions drawn from the analysis and present recommendations for future work in this area.

2 DATA SCRUBBING AND SORTING

2.1 Data Scrubbing

Production data on the Travis Peak wells was obtained from HPDI LLC. (HPDI), that obtains the information from state agencies such as the Texas Rail Road Commission in this case. The data were imported into Wolfram's Mathematica software as a matrix, with each row corresponding to a well and production variables contained in columns.

HPDI provides historic data on oil and gas wells drilled in the United States, therefore the production variables were found to be general, therefore can be applied from conventional to unconventional oil and gas reservoirs.

These variables include identification information such as the API number of the well, geographical information such as longitude and latitude as well as production variables like cumulative production and peak production. Table 2.1 shows a list of these variables with their associated column numbers.

It is important to know that not all these variables are available for each well and not all are relevant to the current research. Moreover, several of the variables are easily computable quantities from the other data stored.

TABLE 2.1	HPDI DATA VARIABLES	
ENTITY_ID	LATEST_WTR	TX_SCRAP
CMN	LATEST_WCNT	FIELD_NO
DISTRICT	PRIOR12_LIQ	MONTHS_PRODUCED
PDEN_TYPE	PRIOR12_GAS	REPORTED_OPER_NAME
PROD_TYPE	PRIOR12_WTR	FORMATION
STATE	FIRST_LIQ	PEAK_GAS
COUNTRY	FIRST_GAS	PEAK_LIQ
PDEN_NAME	FIRST_WTR	LATEST_TEST_YR
API_NO	FIRST12_LIQ	LATEST_FLOW_PRES
COMP_YR	FIRST12_GAS	LATEST_WHSIP
OFFSHORE	FIRST12_WTR	TWP
FIELD	WTR_CUM	RNG
RESERVOIR	WTR_YEAR	MAX3_GAS
LEASE_NO	LIQ_YEAR	MAX6_GAS
COMMINGLE_NO	GAS_YEAR	MAX9_GAS
COMMINGLE_YR	LOCATION	MAX12_GAS
COUNTY_ID	SECTION	MAX3_LIQ
COUNTY	QTR_QTR	MAX6_LIQ
WELL_NO	MERID	MAX9_LIQ
CURR_OPER_ID	OCS_AREA	MAX12_LIQ
CURR_OPER_NO	GOR	MAX3_WTR
CURR_OPER_NAME	YIELD	MAX6_WTR
LIQ_GATH_NAME_1	RKB_ELEV	MAX9_WTR
GAS_GATH_NAME_1	WATER_DEPTH	MAX12_WTR
STATUS	RES_VERT_DEPTH	SUM3_GAS
DRILL_TYPE	MAX_VERT_DEPTH	SUM6_GAS
ELEVATION	SPUD_YR	SUM9_GAS
ELEVATION_TYPE	LATITUDE_BOTM	SUM3_LIQ
TOTAL_DEPTH	LONGITUDE_BOTM	SUM6_LIQ
UPPER_PERF	LATITUDE_EX1	SUM9_LIQ
LOWER_PERF	LONGITUDE_EX1	SUM3_WTR
LIQ_GRAV	PRIOR_LIQ_CUM	SUM6_WTR
GAS_GRAV	PRIOR_GAS_CUM	SUM9_WTR
LIQ_DAILY	PRIOR_WTR_CUM	AVG3_GAS
GAS_DAILY	BASIN	AVG6_GAS
LIQ_CUM	COMMON_OPER_NAME	AVG9_GAS
GAS_CUM	LESSEE_AVAIL	AVG3_LIQ
LATITUDE	YRTAB	AVG6_LIQ
LONGITUDE	LITAB	AVG9_LIQ
LOC_REMARK	GATAB	AVG3_WTR
FIRST_PROD_YR	WATAB	AVG6_WTR
LAST_PROD_YR	TX_BLOCK	AVG9_WTR
LATEST_LIQ	TX_SEC	
LATEST_GAS	SUBSURVEY	

Of all 130 variables only 29 variables were selected to achieve our research objective. Table 2.2 below shows a list of these variables.

TABLE 2.2	**CONDENSED HPDI DATA VARIABLES**	
API_NO	ELEVATION	COMP_YR
FIELD	TOTAL_DEPTH	MONTHS_PRODUCED
COUNTY	UPPER_PERF	FIRST12_GAS
WELL_NO	LOWER_PERF	FIRST_PROD_YR
CURR_OPER_NAME	LATITUDE	LAST_PROD_YR
FORMATION	LONGITUDE	PRIOR12_GAS
STATUS	PEAK_GAS	LITAB
DRILL_TYPE	GAS_CUM	GATAB
BASIN	LIQ_CUM	YRTAB
FIELD_NO	FIRST_GAS	

The first column being the variables used to identify each well, second are those used to locate its geographical position and the third are the production variables.

When the selected variables for each of the Travis Peak wells were printed, some wells were noted to have erroneous values. An example of which is a well stated to have a value of cumulative gas that is less than the reported peak gas, or one whose upper perforation is greater than the lower perforations.

It is expected that the reference point for measurement perforations should be the same. Therefore, the values reported have to be consistent; however, because the data come from the railroad commission, which in turn gets the information from the well operators, it is also expected that the data set will be subjected to human error. The need to filter these wells with erroneous data is apparent.

The filtering criteria included the elimination of the above stated wells and those with negative values of completion year and latitude, positive values in longitude, and wells with upper perforation values greater than lower perforation.

Out of 4800 production wells in Travis Peak, only 3808 wells had complete data, which we called “good sets”. Though 31% of the total number of wells was lost after scrubbing, the good set accounted for 85% of total gas production recorded by HPDI. In the following section we focused on applying the good set of the available data.

2.2 Data Sorting

In the good sets of data, subsets of data were created based on the variables in table 2.2. These included sets by field, formation and basin, in the case when the data include that from multiple fields, formations and basins, by drill type i.e. horizontal, vertical and directional wells, by operator, completion year, by county, reservoir and state.

Each subset will allow the user to easily sort the data by preferred criterion and complete quick analysis. In the case of this research, it allowed for a quick assessment of wells by completion year, by county or by any other variable of interest.

3 DYNAMIC VISUALIZATION OF TRAVIS PEAK PRODUCTION

3.1 Geographical Data Matching

A visual of the Travis Peak area was created with the aid of Mathematica's "CityData" application. This is one of many applications that come with the system and allow a user to input a city name with the data desired and it will output the result. It is capable of providing the properties of the city like, coordinates of the city center, elevation in meters, population and time zone just to name a few.

This application was used to import information the city names, longitude and latitude, and elevation of all cities in Texas and then matched it with the coordinates of the wells in the data from HPDI. Only those cities that fell into the study area were used to map out the locations of these wells.

This map was created by using the city of Carthage – located in Panola County - as a reference point to determine the x-y distance-in miles-of each well from it whereby determining its actual location. Each well was mapped against its corresponding city.

3.2 Production Visualization

An areal distribution of the peak gas rate and cumulative gas production of the good set of wells was visualized on a density plot, where the areas with the highest and lowest production were highlighted as "high" and "low" spots respectively. This density plot was then inserted in the background of the geographical map of wells to visually relate the city these wells were locations to areas with good production relative to the other wells in the data set.

A “ToolTip” application from Mathematica was used to insert detailed identification information and brief production information into each well. This is the dynamic aspect of the visualization, where a user can place the mouse pointer at a specific well and these details will be displayed.

The displayed information will allow a user to look at areas with high or low production and select wells of interest to determine how old the well is, if it is active or not, how long it has produced for, which city its located near to it and also the API number of the well, all instantaneously. The program was written in a way that will allow for easy modification to users preference. Figure 3.1 below shows the dynamic visualization of peak gas in Travis Peak.

This graph shows a 140 by 120 mile view the area studied in this research. The point zero-zero identifies our reference point, the city of Carthage that was used to map these wells. The negative axial labels identify the mile distance West and South of the city of Carthage, where the positive labels identify the mile distance North and East of it.

The orange rings are the locations of cities close to the coordinates of the wells in our good set of data. The blue dots are the actual wellheads and the yellow to red stains represent good peak gas rate relative to other wells while the white to blue stains represent the poor peak gas production.

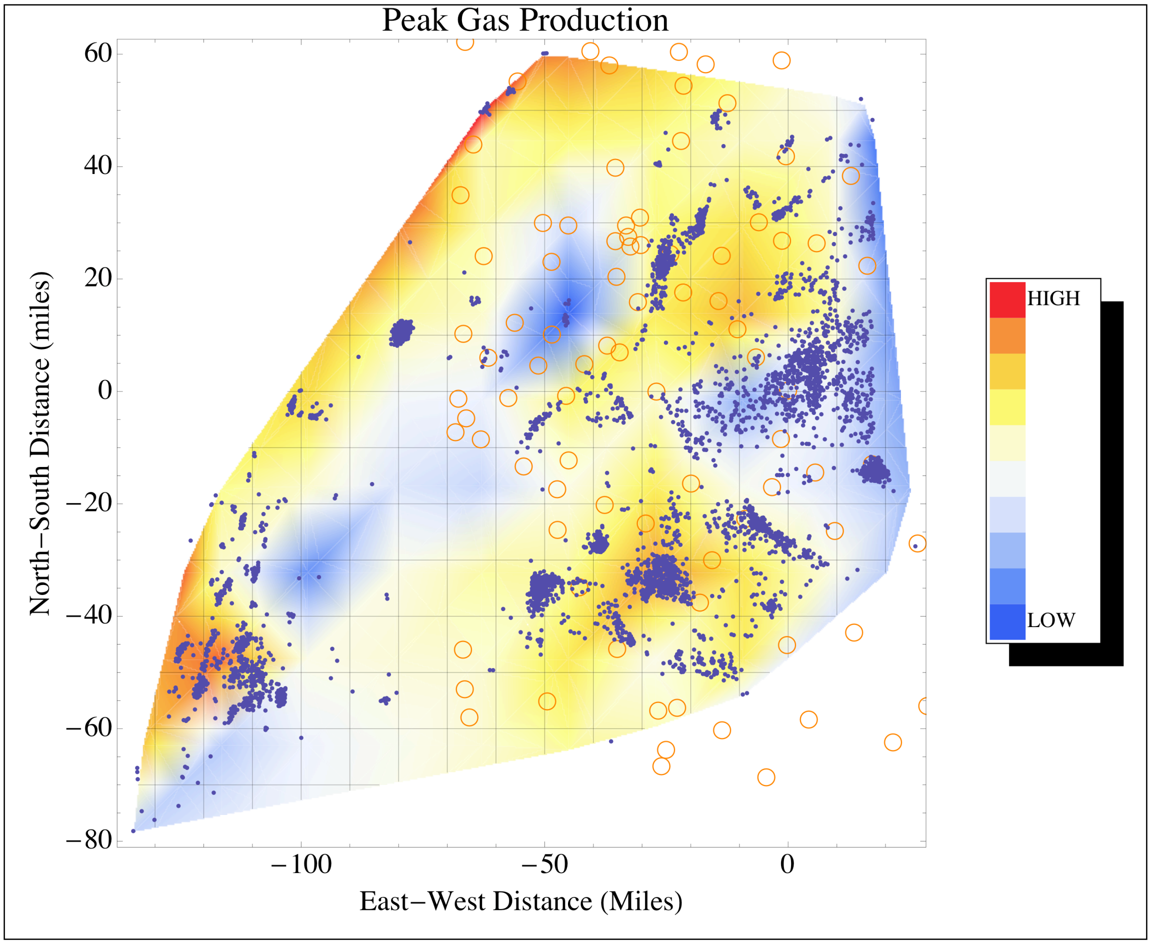

Figure 3.1- Areal distribution of peak gas rate with well locations in Travis Peak

Looking at the distribution of wells, it is apparent that all cluster of wells are not located where we have high peak gas. In particular, the cluster close to the city of Carthage – located at coordinate zero-zero - is noted to have low peak gas rates. Taking a closer look at these wells, we find that some of them were old wells with low initial production that did not produce for very long and are currently inactive; however, majority of them are newer wells completed within the last decade, after 1998. A visual representation of the areal distribution of cumulative gas production was also created; this is shown in Figure 3.2 below.

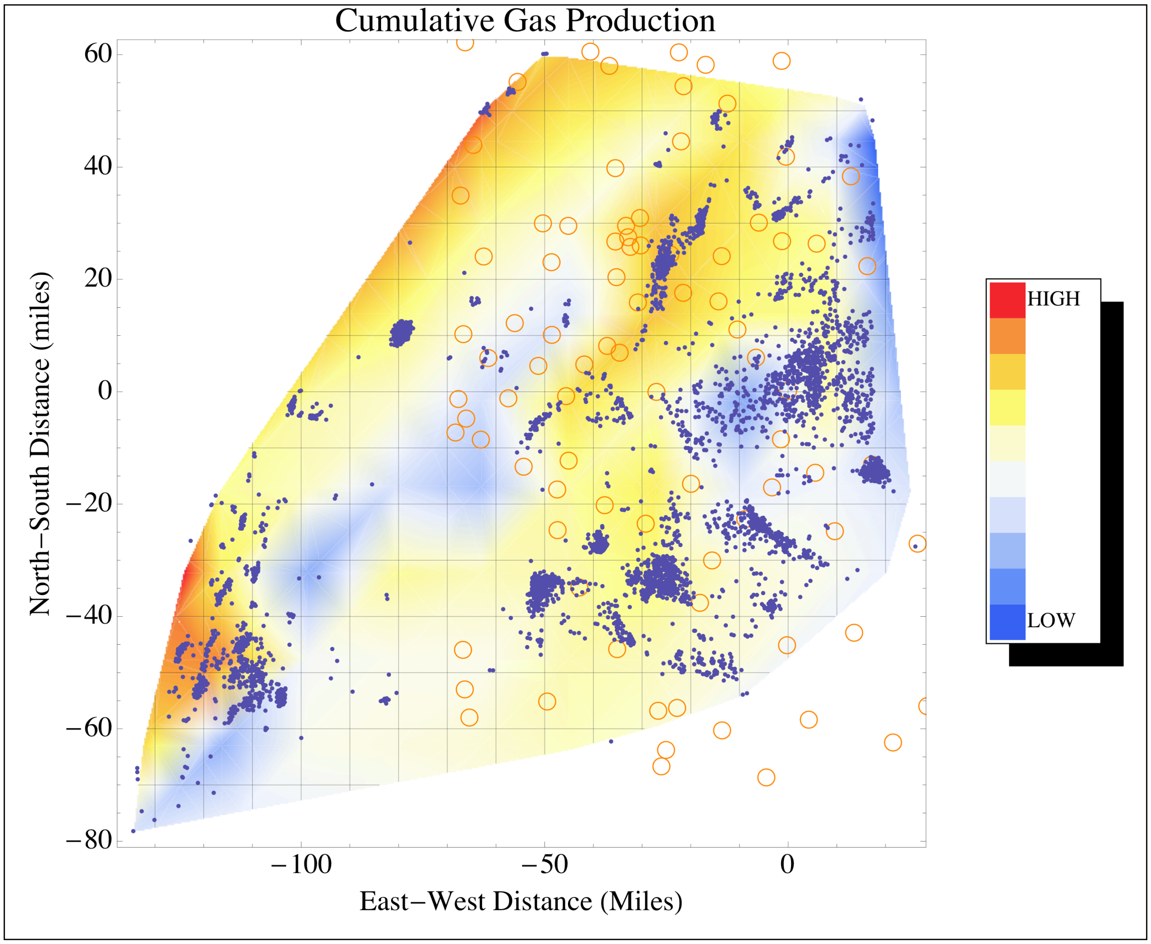

Figure 3.2- Areal distribution of cumulative gas production with well locations in Travis Peak

The map above looks similar to that for peak gas production, implying that area with relatively higher peak gas production also produced cumulatively more gas relative to other locations. At the same time areas with low peak gas production also had low cumulative production.

4 STATISTICAL ANALYSIS OF TRAVIS PEAK PRODUCTION

4.1 Overall Outlook of Travis Peak

Understanding that production wells will be located where there is economically producible volumes of gas-in-place; given the inconsistent reservoir properties learned from the literature reviewed, it is expected that the locations of wells in Texas will be unevenly scattered over the area of study. This is shown in Figure 4.1 below.

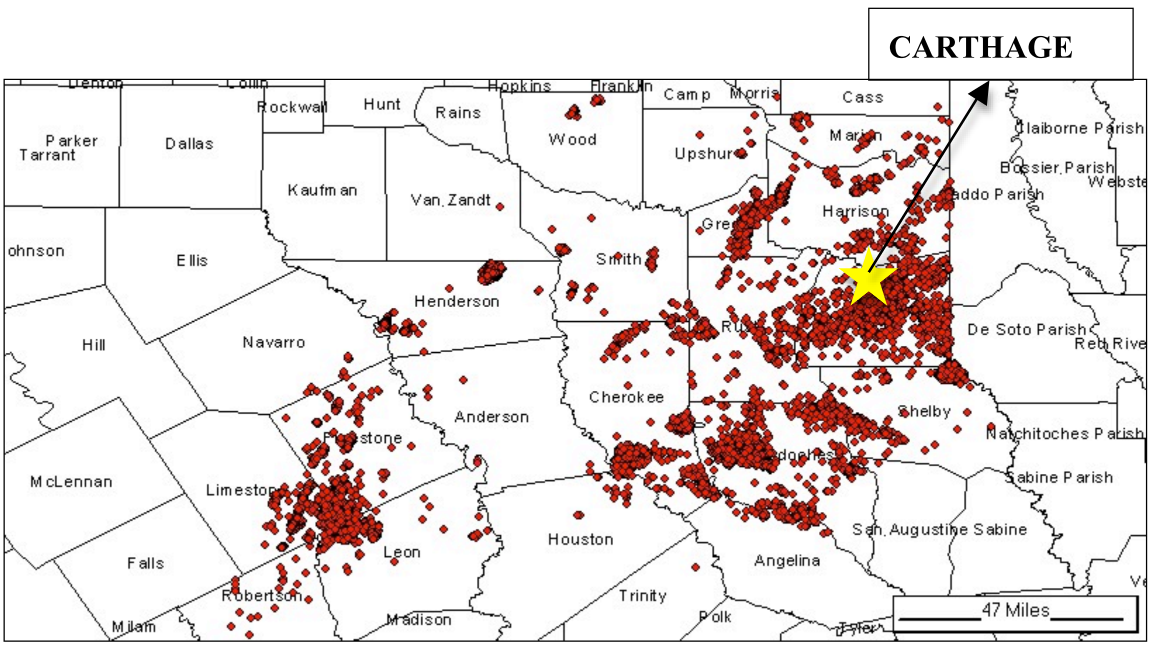

Figure 4.1- Areal distribution of Travis Peak wells in east Texas

As expected, clusters of well are found at specific locations across the area. It is important to note that the concentration of wells was found to increase Southeastward from Wood County to Panola County. This can be explained by the trend of increasing formation thickness in the southeastern direction from the northwest part of the region (Syfan and Robinson 1993).

Looking at the types of well drilled in this area, it is apparent that vertical wells are most popular, with a small fraction of directional wells and a minimal number of horizontal wells. Figure 4.2 below shows this distribution by percentage from the good sets of data.

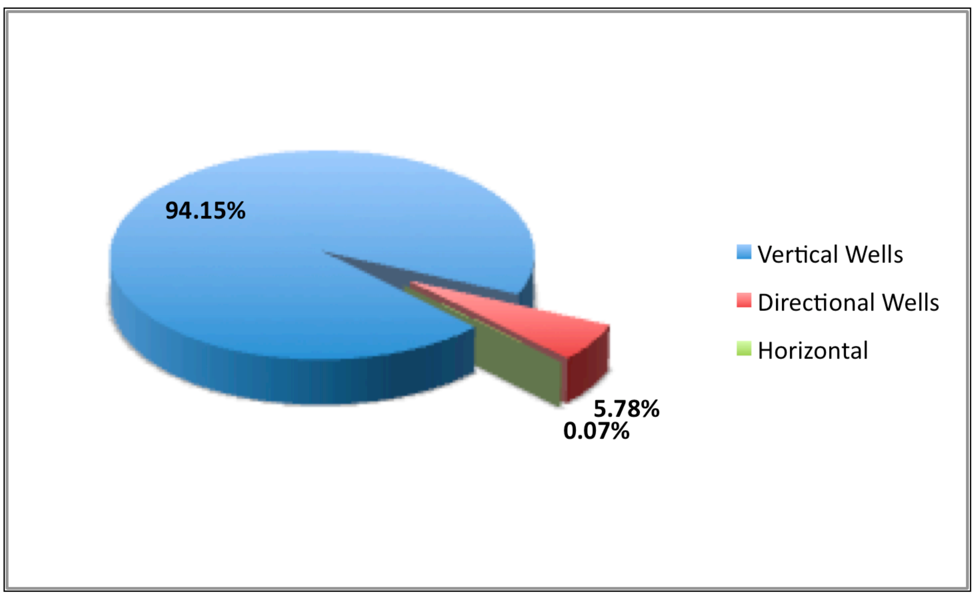

Figure 4.2- Distribution of wells in Travis Peak

Cumulatively, vertical wells were found to have the highest gas production of just less than 95% of total gas produced in that area and directional wells accounted for 5% and horizontal wells accounted for a very small fraction of less than 1%. It is clear that vertical wells perform better in this formation, and therefore, the remaining analysis will focus on vertical wells.

4.2 Analysis by Completion Year

The good data sets were sorted by completion year and the number of wells completed was plotted on a bar chart, this is shown in Figure 4.3 below.

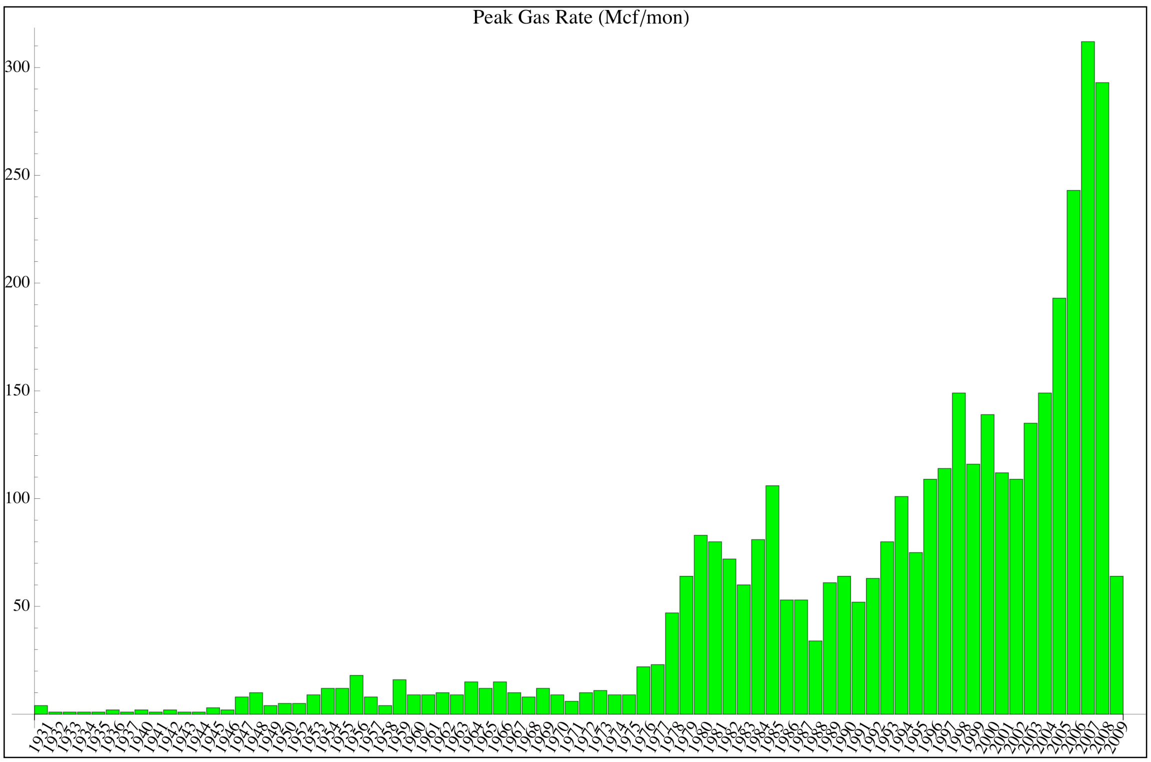

Figure 4.3- Annual number of completed wells in Travis Peak

It is apparent that the number of wells has exponentially increased from the early 1930’s to recent time; however, there was a significant drop in number of wells in 2009.

Looking at the historic data on wellhead price of natural gas obtained from the Energy Information Administration, we found that the above trend was duplicated. Figure 4.4 shows this below.

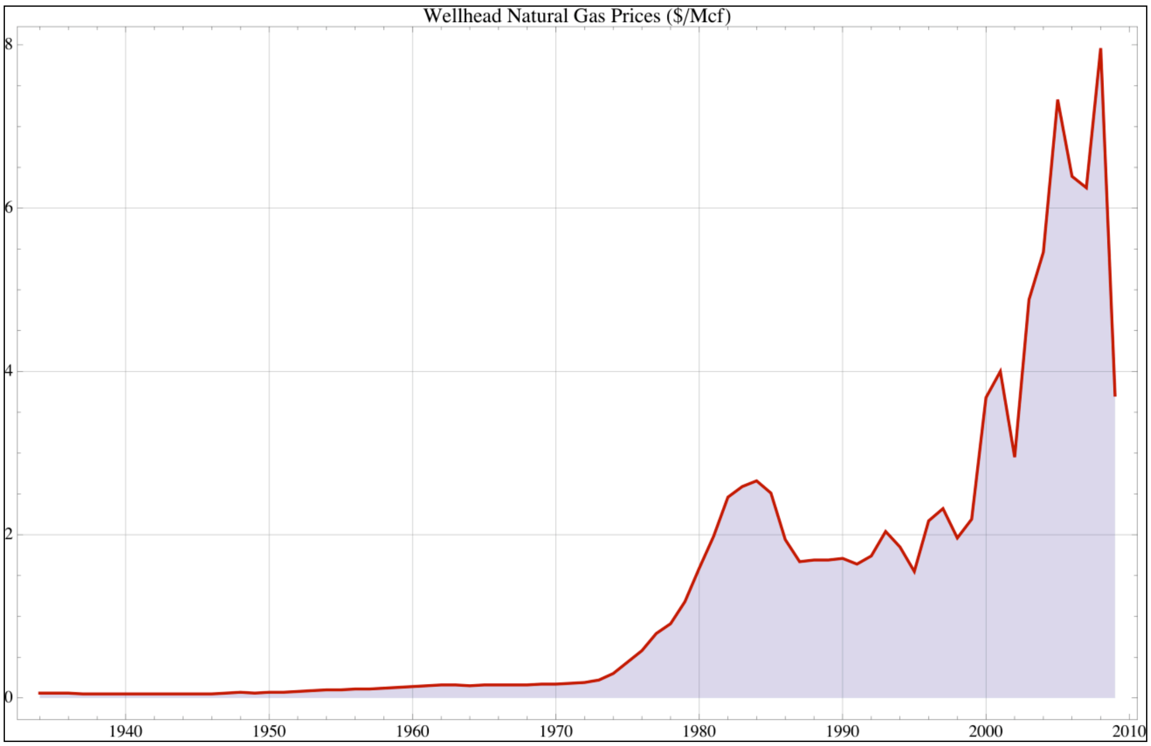

Figure 4.4- U.S. natural gas wellhead price in dollars per thousand cubic feet

Figure 4.4 also shows a peak gas price in 2008 at $7.96 and a significant drop in 2009 to $3.71. It is accurate to say, from both observed trends that wellhead gas prices is a strong predictor of number of wells to be completed.

A chart of average production time-in months-of these wells showed that an average well completed in 2006 and 2007 has produced for longer than 24 to 36 months. Considering the exponential increase of gas prices, it is logical to say that operators were able to afford to recomplete older wells to produce more. This chart is shown in Figure A.1 in Appendix A**.**

A chart of initial gas production rate was also created, and we found that it was higher for older wells completed in the early 1930's to the early 40’s, after which it was noted to drop. Then initial gas rate decrease as you get into the 1960's and remained relatively constant through the late 70’s when the next drop in gas rate was noted. In the early 80’s, a progressive increase in gas rate was seen till 2008. This chart of initial gas rate is shown in Figure 4.5 below.

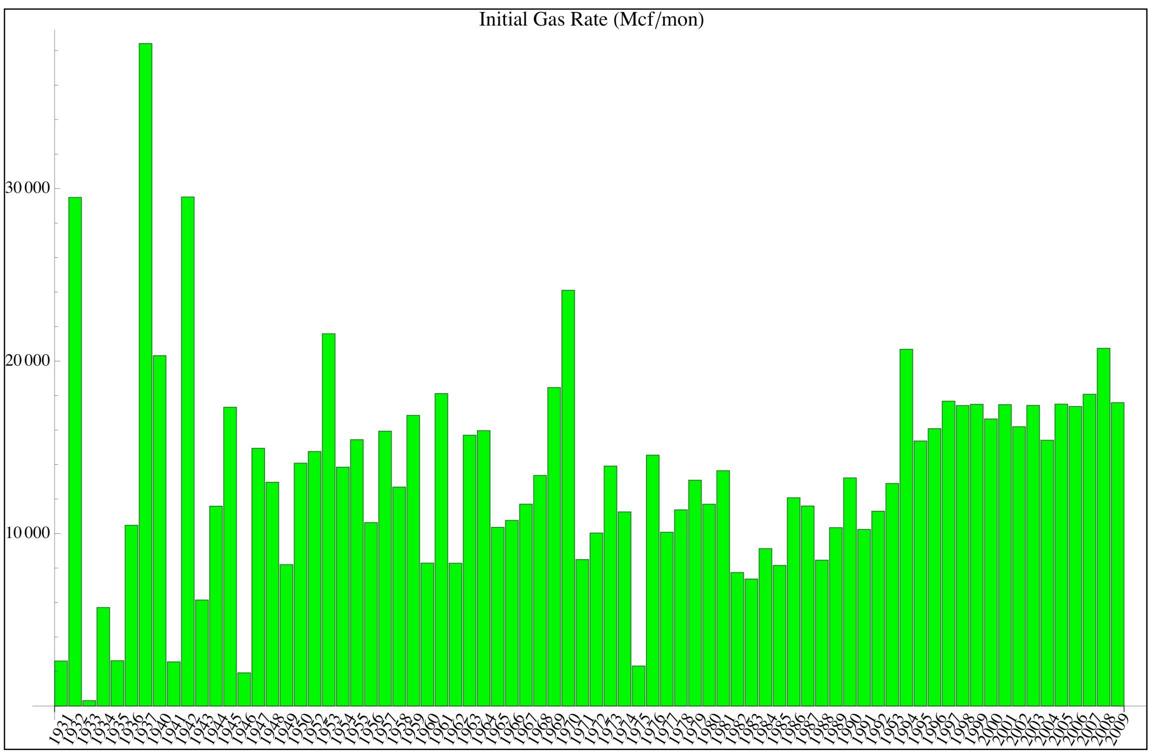

Figure 4.5- Initial gas production rate for annual completions

Taking a closer look at the above figure, there is an apparent trend of instability in initial gas rates for older wells that is not observed for wells completed after the early 80's. This is a demonstration of the level on uncertainty operators took in the determination of locations for older wells and how it has improved at recent times.

The trend noted from peak gas rate shows that older wells completed before the early 1970's had gas rates as high as 54,497 mcf/mon while a significant reduction was observed after to about 12,525 mcf/mon and it remained constant till the late 80's, where there was another increase until 1994 and it peaked at 46,858 mcf/mon and then it remained relatively constant till 2009, this chart can be seen in Figure A.2 in Appendix A.

The trend in peak gas rate can also be attributed to the trial an error approach taken in locating and completing older wells. The observed increase in gas prices afforded operators better stimulation technologies combined with improved engineering, newer wells demonstrated a more stable trend in peak gas production.

4.3 Analysis by Location

The clusters of wells shown in Figure 4.1 were identified and group into the counties they are located in, then analyzed by peak production, cumulative production and condensate production. Table 4.1 shows a summary of these production variables for these counties.

The tables has a record of condensate production in our study area, as it is known that condensate formation in the wellbore and surface production equipment accompanies pressure during production (Lee and Watternbarger 2002). However, looking closer, we found that Franklin and Cass County had the highest percentage of 5.11% of total production to be condensate, there the rest of the area, had less than 1% of total production for an average well to be condensate. Therefore liquid production does not have significant impact on gas production in Travis Peak.

TABLE 4.1 TRAVIS PEAK PRODUCTION SUMMARY BY COUNTY

WELLS	COUNTY	DEPTH (FT)	CUM GAS PROD (MCF)	CUM LIQ. PROD (MCF)	PEAK GAS PROD (MCF/MON)	MONTHS PROD
739	PANOLA	7898.10	6.86E+05	2.18E+03	2.51E+04	108.1
661	NACOGDOCHES	7717.46	5.07E+05	2.06E+03	3.79E+04	64.4
416	CHEROKEE	8035.59	6.68E+05	3.10E+03	3.53E+04	122.4
298	SHELBY	7719.47	7.84E+05	3.83E+03	4.00E+04	98.2
272	HARRISON	7736.55	6.81E+05	6.15E+03	2.78E+04	127.4
263	FREESTONE	7675.26	8.80E+05	3.37E+03	3.50E+04	125.4
211	LIMESTONE	7825.38	1.03E+06	1.89E+03	4.35E+04	107.2
201	HENDERSON	8272.92	1.83E+06	5.98E+02	4.77E+04	198.2
184	RUSK	7326.81	3.54E+05	5.37E+03	1.92E+04	85.7
177	GREGG	7732.42	1.30E+06	9.16E+03	3.52E+04	188.1
157	LEON	8053.06	7.00E+05	4.20E+03	3.40E+04	105.8
51	SMITH	8317.64	7.26E+05	2.02E+04	2.99E+04	96.8
45	MARION	8559.06	4.95E+05	4.56E+03	2.37E+04	100.8
43	ANGELINA	8673.85	4.44E+05	3.42E+03	3.13E+04	64.6
22	WOOD	7223.81	1.01E+06	2.29E+04	3.77E+04	165.3
17	ROBERTSON	7599.20	4.73E+04	4.58E+01	8.31E+03	28.4
16	HOUSTON	8942.34	3.19E+05	4.20E+02	3.62E+04	20.4
10	UPSHUR	7541.99	3.72E+05	1.08E+04	3.46E+04	41.8
10	NAVARRO	8748.69	7.36E+05	2.29E+03	3.53E+04	83.1
4	SAN AUGUSTINE	8001.15	2.72E+05	1.40E+03	4.66E+04	19.8
4	ANDERSON	6948.82	2.76E+04	7.45E+02	4.71E+03	26.0
3	FRANKLIN	12958.22	5.49E+05	2.95E+04	5.93E+04	81.3
2	CASS	4281.50	5.11E+04	1.81E+03	4.90E+03	21.5
1	VAN ZANDT	1607.61	4.91E+05	7.83E+03	4.13E+04	54.0
1	TRINITY	2125.98	1.30E+05	6.90E+01	1.74E+04	61.0

According to Saucier, Finley, et al. 1985, the formation can be found at a drilling depth of less than 10,000 feet. This is evident in the data presented above; however, there is an apparent wide range in average well depth per county from 6,095 to 14,570 feet as seen in the above table, clear indication of the variation in burial dept of the formation.

This variation in burial depth is not consistent with the peak gas rates for an average well in each county as an average well in Nacogdoches County is drilled to 7717 ft and has a peak gas rate of 37,900 mcf/mon where an average well in Rusk County drilled to about the same depth has a about half the peak gas rate of Nacogdoches County. The fact that the areal distribution of reservoir properties are not uniform in Travis peak (Dutton and Diggs 1992) may account for the inconsistent nature of production rates across these counties.

Taking a closer look at the peak production rate for an average well in each county, a bar chart was created and is shown in Figure 4.6 below.

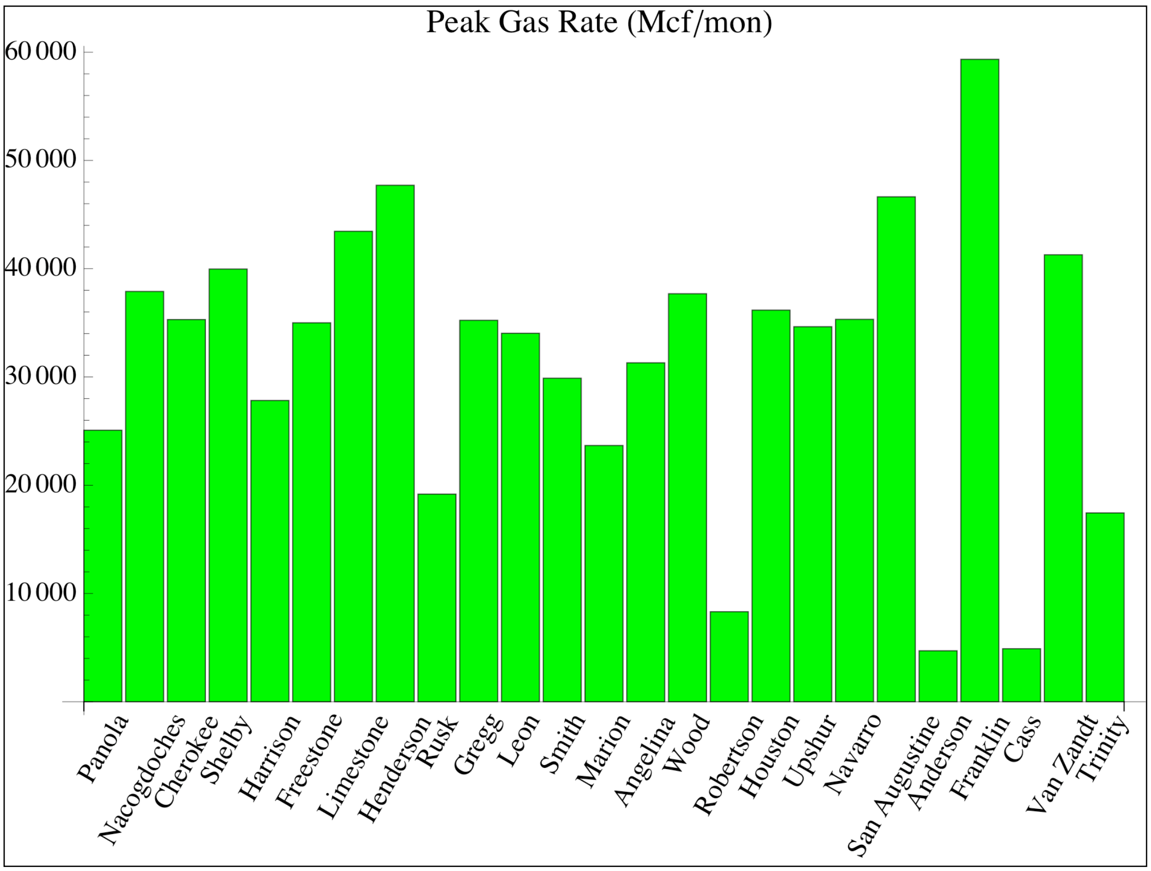

Figure 4.6- Average peak gas production rate for an average well in east Texas counties

From the chart above, an average well in Franklin County is noted to have the highest average peak production rate well with 59, 340 mcf/mon and San Augustine coming close behind with 46,640 mcf/mon. It is important to note that Franklin County has only 3 wells that have produced for an average of 81 months compared to San Augustine County with 4 wells and an average production time of 20 months. This may be because these wells relatively new with the application of better stimulation technology.

It is a logical expectation that wells with longer production time will have a larger cumulative production as in the case of Henderson County with the longest production time of 198 months has a cumulative gas production of 1,832,830 mcf. This trend was not observed as you go from the county with the longest average well production life to that with the shortest. Harrison County with the 4th longest production life for an average well does not have the 4th highest cumulative production. Well stimulation technologies may also influence these observations as many of these wells were hydraulically fractured according to the well documents filed at the Texas Rail Road Commission. A bar chart of cumulative gas production can be found in Figure A.3 in Appendix A**.**

The variation in average production raises the question whether these production variables follow any trend when looking into an individual county's production data. One can expect equally large variations from well to well within each of these counties. The next section will assess wells in specific counties for production trends in attempt to select variables with good predictive potential. We will start with wells located in one of the areas with high peak gas rate and cumulative gas.

4.3.1 Angelina County Production Analysis

Angelina County is located in one of the areas with high peak gas in Figures 3.1 and 3.2 that show the areal distribution of peak gas rate and cumulative gas production. Forty-three wells were analyzed in this county by relating different production variables to look for trends between them. The oil and gas potential records from the Texas Railroad commission showed that many of these wells were hydraulically fractured or acid fractured. Some of these stimulation treatments were unsuccessful and the wells were plugged and abandoned.

In this analysis, we first looked at the relationship between perforation thickness and the burial depth, then we looked for trends between peak gas rate and burial depth. Both investigations were inconclusive as shown in Figures A.4 and A.5 in Appendix A.

Then peak gas was related to perforation length on a Log-Log plot as shown in the Figure 4.7 below.

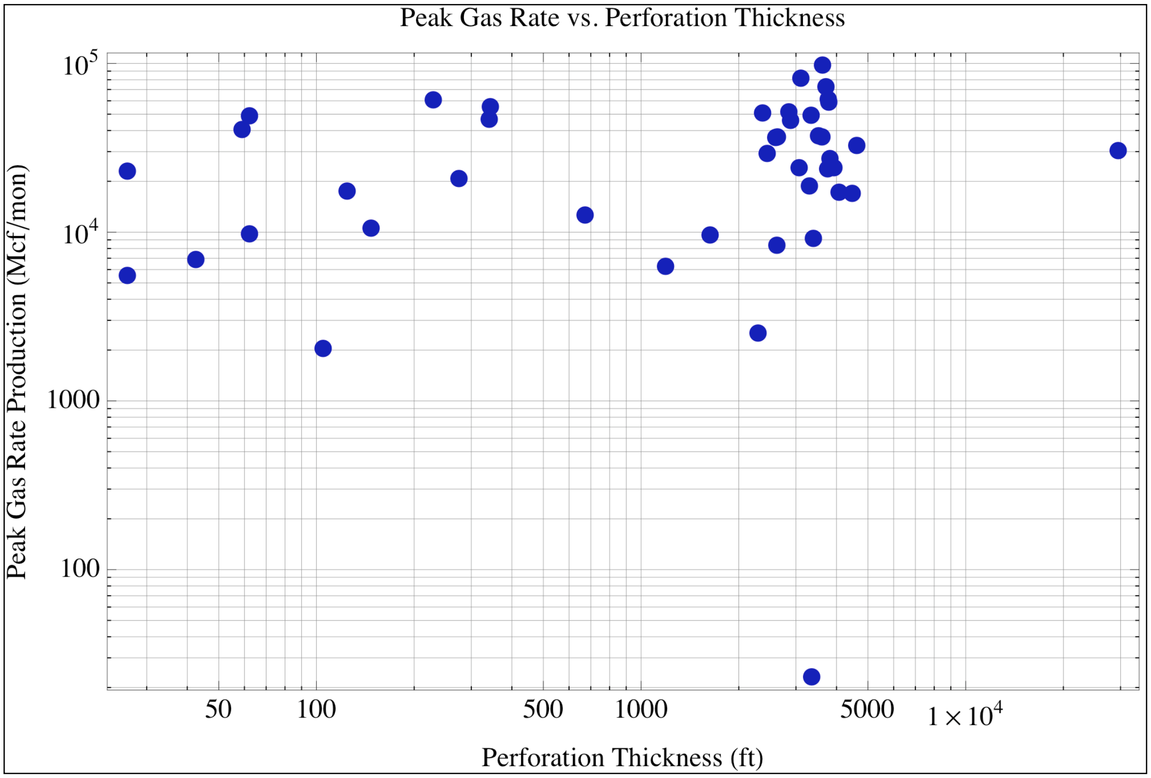

Figure 4.7- Angelina County peak gas rate vs. perforation thickness

There is a hint of a trend showing an increase in peak gas rate as perforation thickness increased; however, it is not significant enough to make a conclusive correlation between both production variables.

Peak gas rate was also related to completion year. Two clusters of peak gas were noted: the first was for wells completed in the 1980's and the second was for wells completed after 2005. It is important to note that the range of spread of peak gas rate in the cluster of older wells is less than that in the newer cluster. Taking into consideration the improvement in technology and increase in gas prices from the 1980's to recent times, it is logical to say that operators were able to afford more efficient stimulation methods at recent times. Therefore, we hypothesize that wells completed after 2005 are more likely to have a higher peak gas rate than wells completed before 1985. This graph can be found in Figure 4.7.

The initial production rate of these wells was also graphed against the year of initial production, most recent production rate, and production life. These graphs are shown in the Figures 4.8 and 4.9 below.

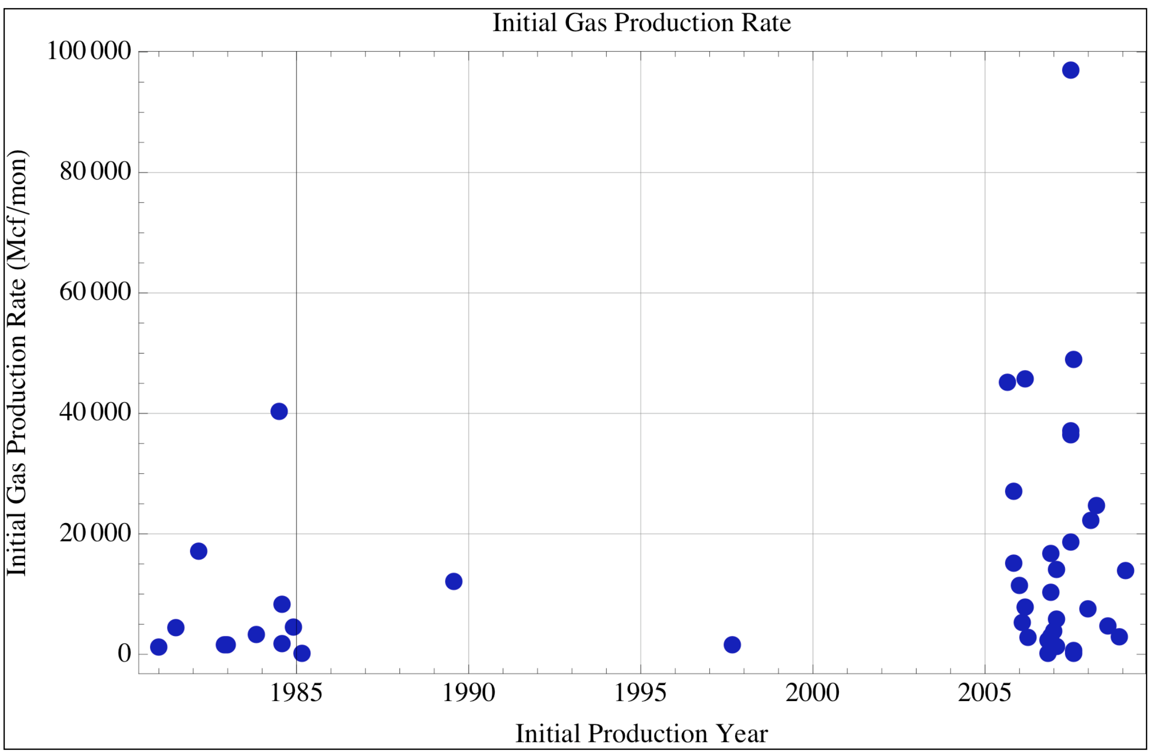

Figure 4.8- Initial production rate of wells in Angelina County

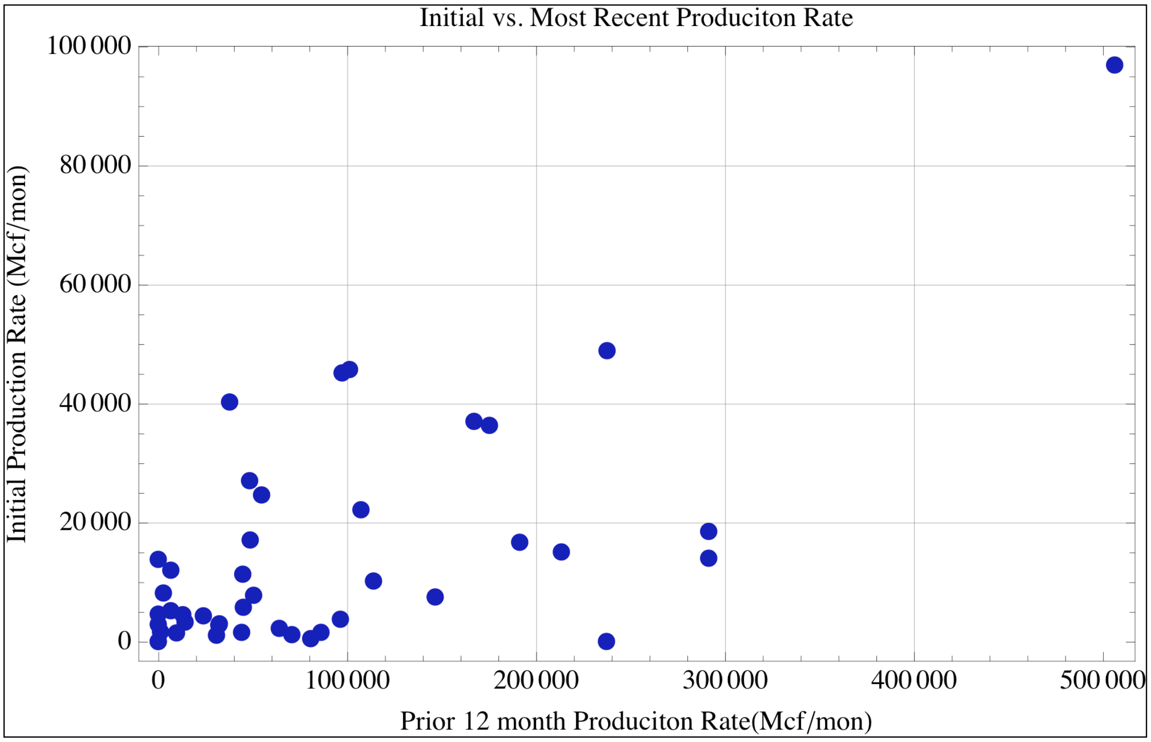

Figure 4.9- Initial vs. most recent production rate of wells in Angelina County

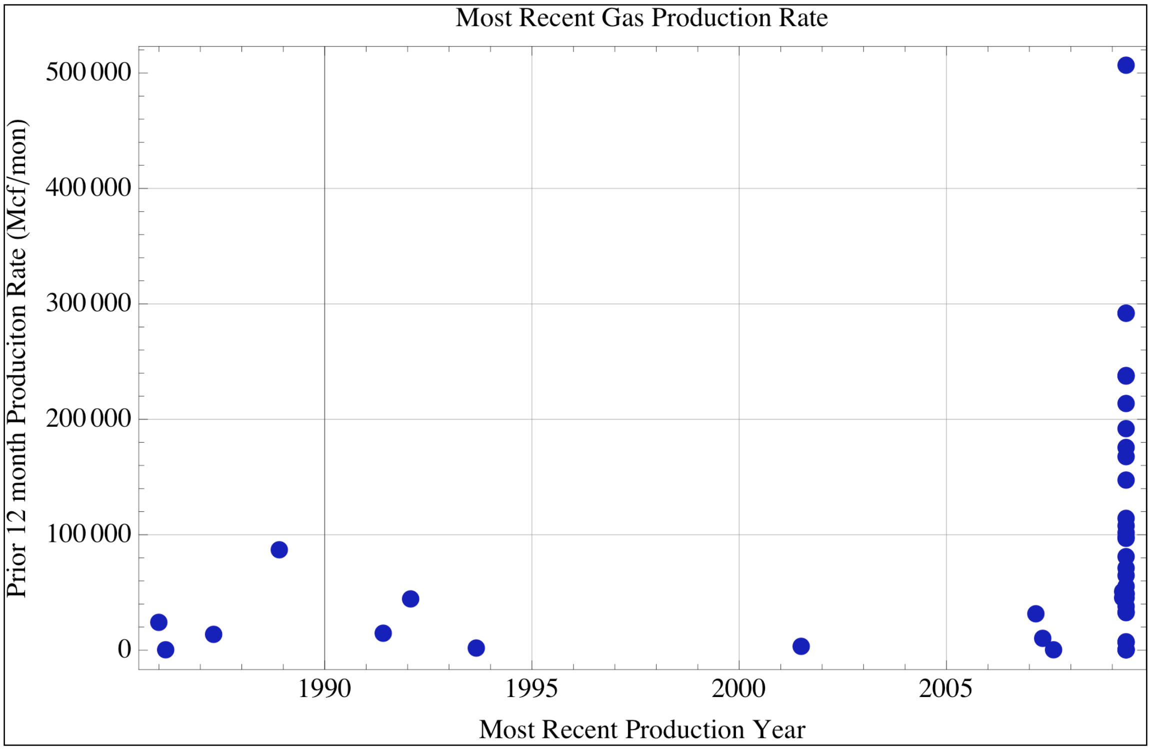

Figure 4.10- Most recent production rate vs. last production year

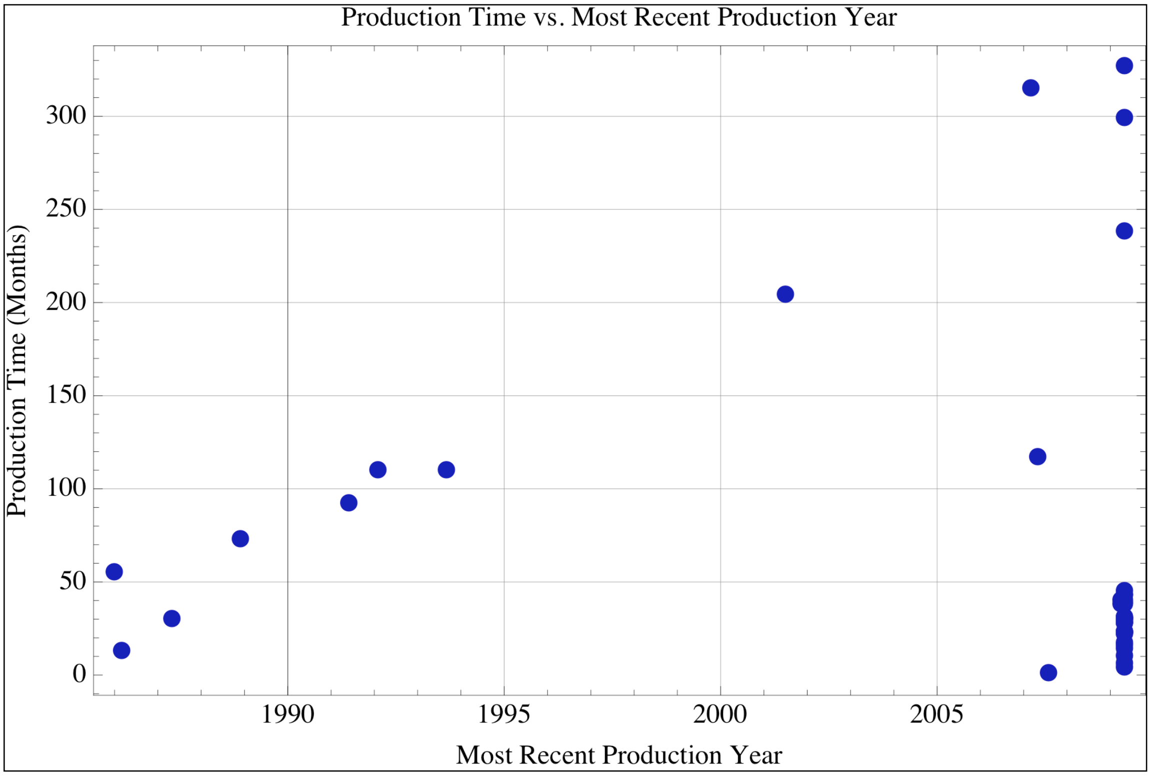

Figure 4.11- Production time vs. last production year

Two clusters of production rates was found in Figure 4.8: one for wells that started producing before 1985 and that for wells completed after 2005, with the latter cluster having a higher range of scatter in initial production. The high price of natural gas after 2000 can be attributed to the success of newer wells. Operators can afford better wells stimulation technologies, increasing the likelihood of high initial gas production, if contacting formation with sufficient gas. One can hypothesize that newer wells are more likely to have a higher initial production than older wells.

Looking at the relationship between the initial production rates and the most recent rates shown in Figure 4.9, it is apparent that wells with relatively low initial production rates were also the same wells with relatively low most recent production rate. Wells with higher initial rates also had higher most recent production rates. This implies that wells maintained their relative performance throughout the production life; however, there were a few wells with relatively low initial production rates that had higher most recent rates, these are examples of successfully re-stimulated wells. Indeed, we found information on restimulation activities in the Texas Rail Road Commission's oil and gas potential records.

The most recent production rates were graphed against the year they last produced as seen in Figure 4.10. Wells with relatively low production rates were noted to have stopped producing as early as the early 1990's. They were also found to have relatively low production life compared to wells that are still producing as seen in Figure 4.11. From this one can say that wells with low production rates did not perform well relative to others and are more likely to have a shorter production life and stop producing early.

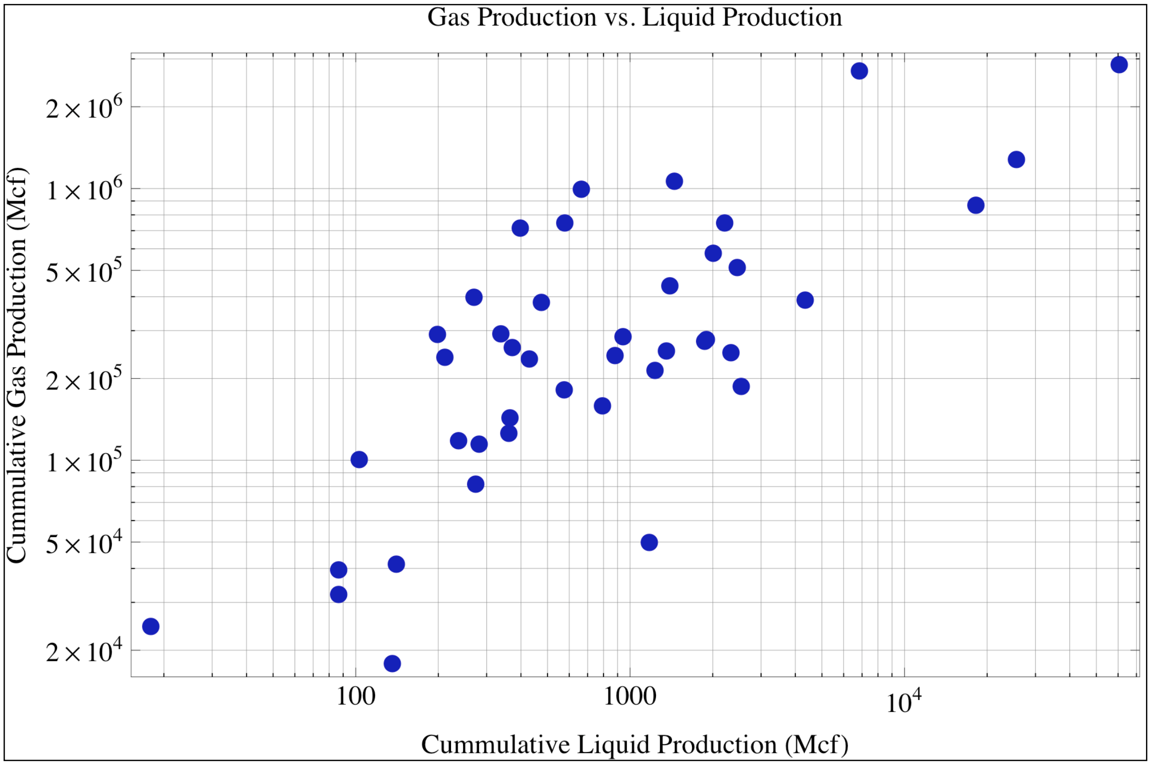

Figure 4.12- Angelina County gas production vs. liquid production

Condensate production was graphed against gas production on a Log-Log scale and an increasing trend was noted, implying that wells with relatively high cumulative gas production are more likely to have a relatively high cumulative liquid production. This is shown in Figure 4.12 above.

A graph showing the decline in gas production rate of individual wells in Angelina County was created with production year and it was apparent that wells completed after 2005 performed better than those completed prior to 1995. This is with the exception of a couple of old wells that were originally completed in the early 1980's. Those older wells outperformed other wells as result from successful recompletion. These graphs are shown below in Figures 4.13 and 4.14 respectively.

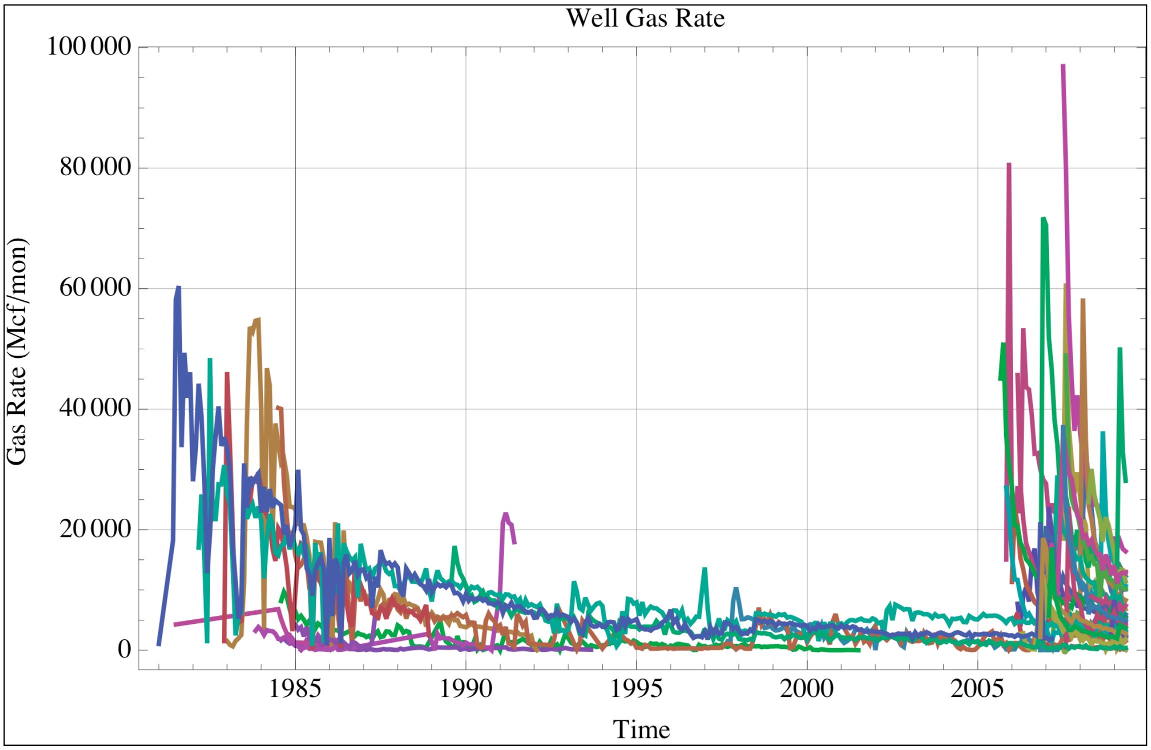

Figure 4.13- Angelina County gas production gates

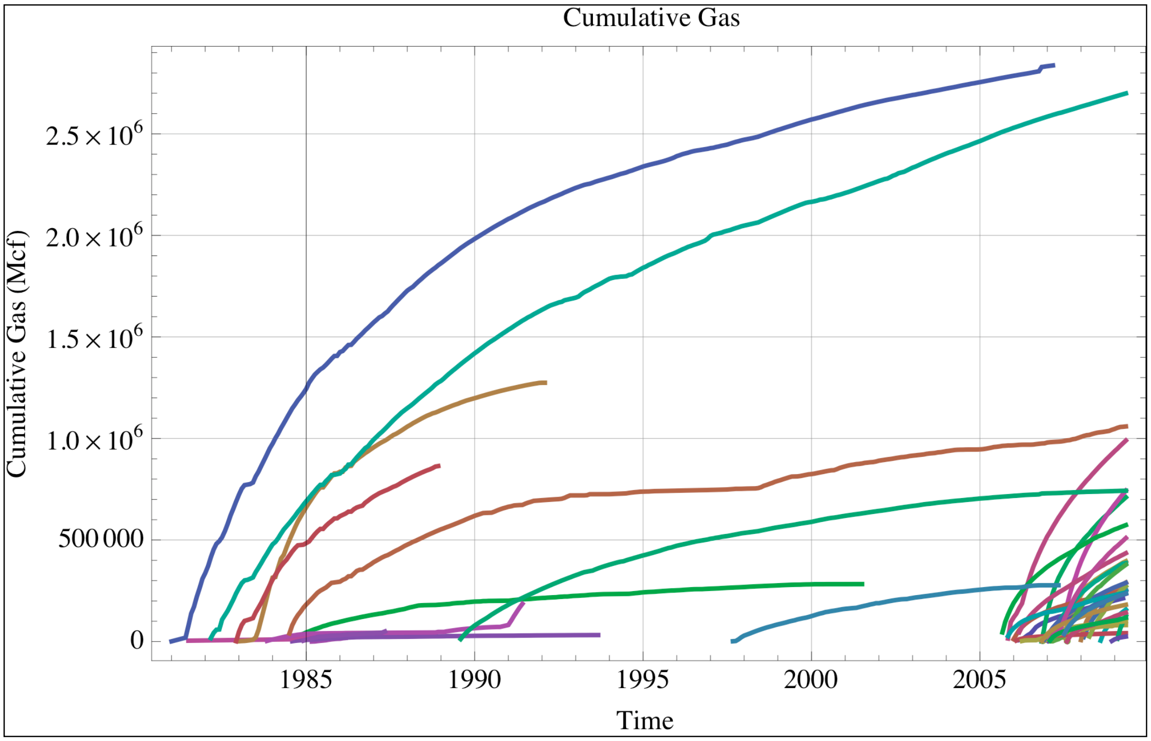

Figure 4.14- Angelina County cumulative gas production

4.3.2 Leon County Production Analysis

Leon County is located in one of the areas with low peak production shown in Figures 3.1 and 3.2. It has 157 wells, some of which started producing as early as the 1930's. Figure 4.15 below shows the annual number of new wells in this area.

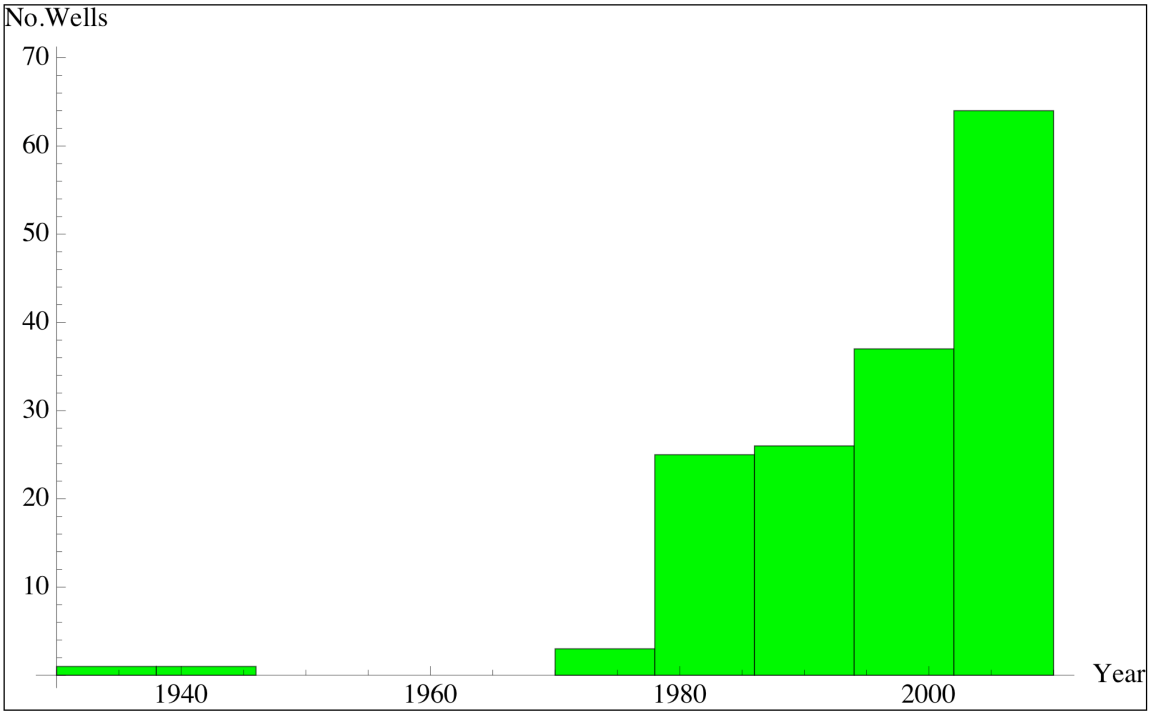

Figure 4.15- Annual number of new wells in Leon County

From the above histogram, it is clear that the above trend is driven by natural gas prices as the number of wells increased from the early 1980's to recent times. Four wells were completed before 1980, this number increased to 50 between 1980 and 1991, and to 103 between 2000 and 2009.

A similar analysis to the one conducted for Angelina County was also conducted for this area. Perforation thickness was related to reservoir depth, and peak gas rates and no observable trend was found. Initial production rate was related to initial production year and most recent production rate and there were no observable trends between these production variables. Cumulative gas production was related to cumulative liquid production and liquid production was found to increase with increasing gas production. These graphs can be found in Appendix A.

The decline in gas rate for each well was graphed with production year as shown in Figure 4.16 and it was found that the peak gas rate increased from the 1970's to present time in accordance to our knowledge of improvements in well completion technology.

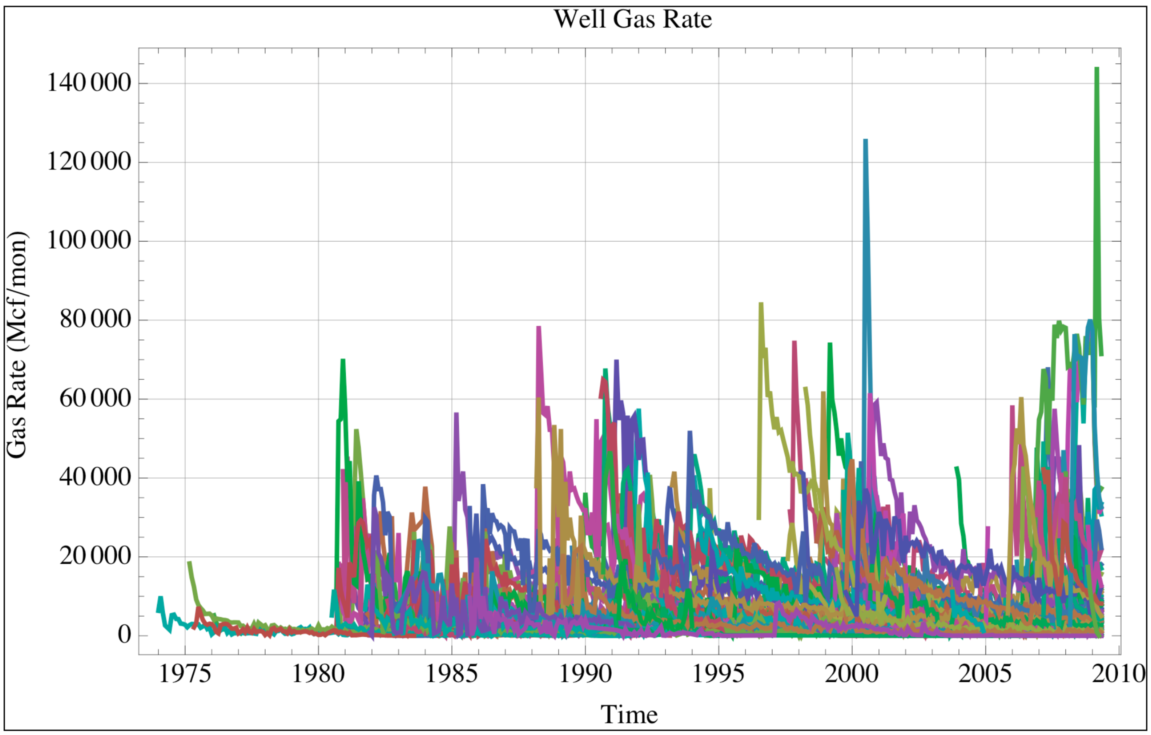

Figure 4.16- Leon County gas production rates

Looking at the cumulative production for each well in Figure 4.17, it was apparent that some older wells did not produce good volumes of gas relative to the others and therefore did not produce for very long. Overall, some wells outperformed others, however, there was no clear distinction - like that seen in Angelina County-between wells that started producing in the 70's and those that started producing at recent times.

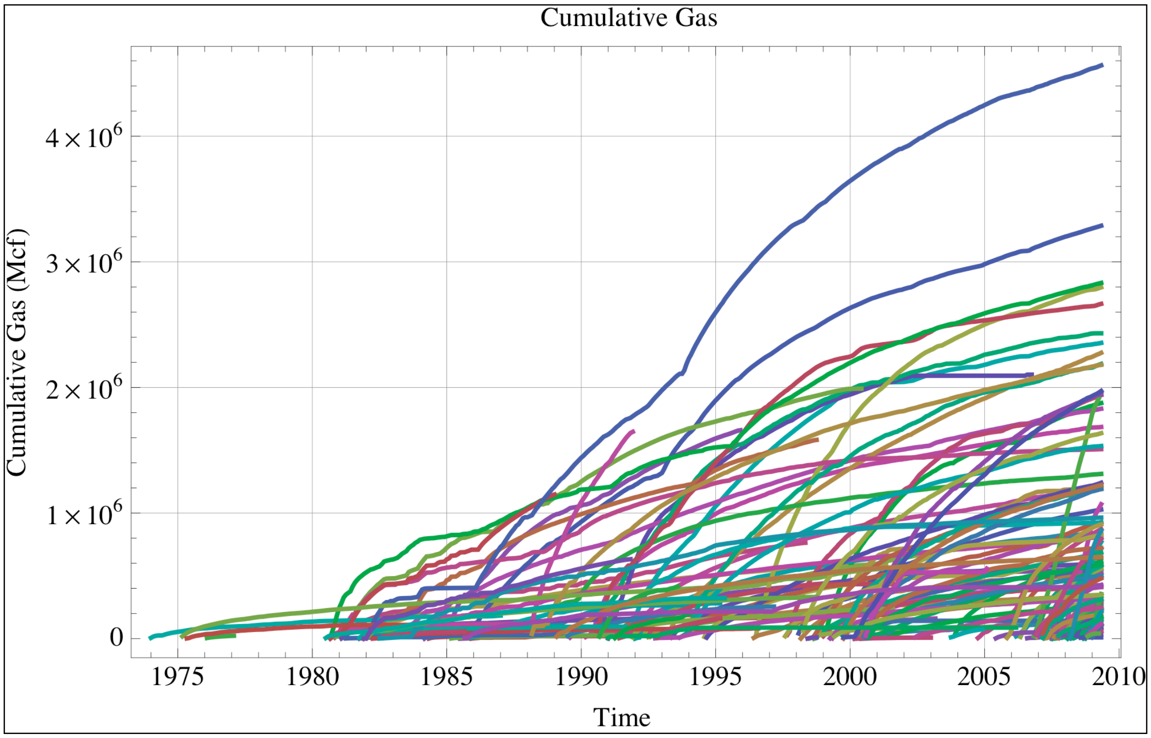

Figure 4.17- Leon County cumulative gas rates

More importantly, cumulative gas production trend observed shows that gas production continues to increase at recent times, implying that this area is yet to approach depletion.

4.3.3 Harrison County Analysis

Harrison County is also located in one of the areas with high peak gas rates and cumulative gas production. There are 272 wells in the area with over 60% of the wells drilled before the 2000 as shown in Figure 4.18 below. The overall trend shows a striking resemblance to that of wellhead gas prices shown in a previous section.

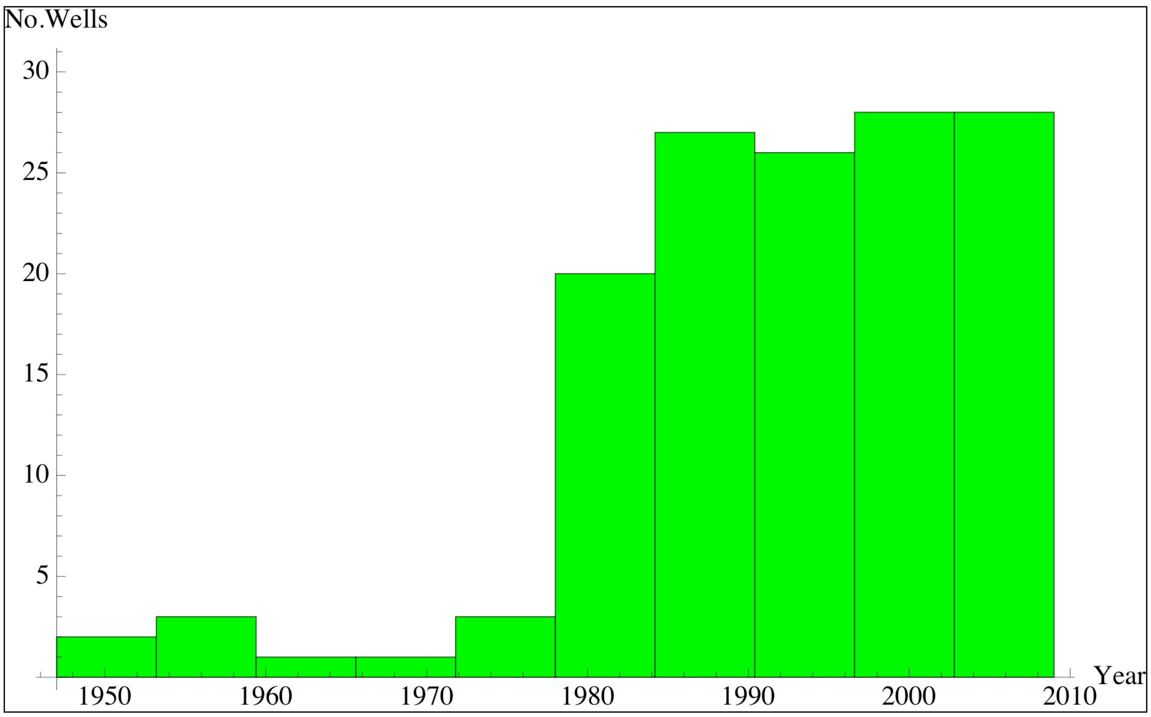

Figure 4.18- Annual number of new wells in Harrison County

We searched for possible predictors of well performance among the variables but like in the case of Leon County, no observable trends were found; however, when the individual gas rates of each well were assessed, peak gas rate was found to increase significantly from the 70's to the early 80's and a steady increase was noted till recent times. This trend is shown in Figure 4.19.

In Figure 4.20, cumulative gas production for older wells were noted to be very low relative to other wells, a significant increase was found for wells that started producing in the early 1980's and a drop was observed for wells that started producing at recent times. The trend in cumulative gas of wells in this area is yet to have a flat profile, implying that these wells are yet to approach depletion.

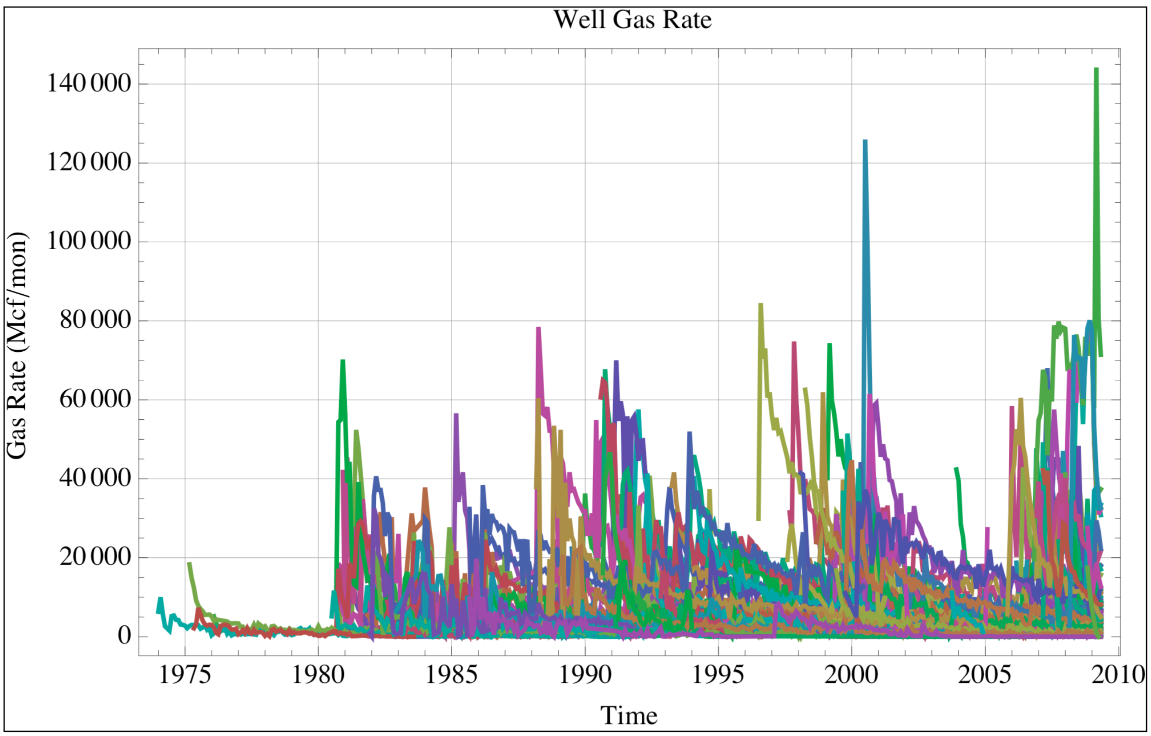

Figure 4.19- Harrison County gas rates

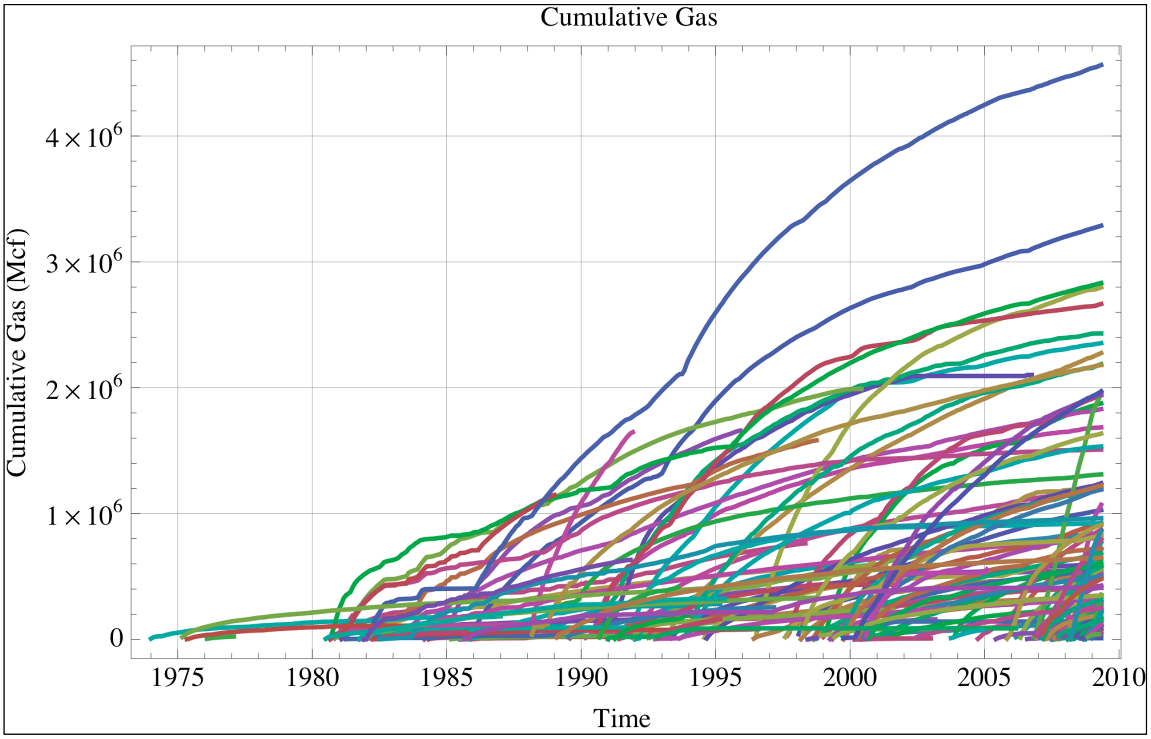

Figure 4.20- Harrison County cumulative gas production

4.4 Analysis by Percentage of Recent Completions

From the previous section, we learned that the completion year of these wells is correlated to the stimulation technology applied, which relates to the likelihood of individual wells' successful gas production. Table 4.2 below, shows the producing counties arranged in order of increasing percentage of wells completed after 2000.

TABLE 4.2	PERCENTAGE OF RECENT COMPLETIONS, ACTIVE AND INACTIVE WELLS BY COUNTY		
County	% Completed after 2000	% Active Wells	% Inactive Wells
VAN ZANDT	0	0	100
NAVARRO	0	10	90
CASS	0	0	100
FRANKLIN	0	33	67
MARION	9	7	93
WOOD	9	36	64
GREGG	10	41	59
ROBERTSON	18	6	94
HARRISON	22	39	61
RUSK	25	28	72
SMITH	25	31	69
FREESTONE	26	51	49
PANOLA	35	42	58
HENDERSON	48	77	23
ANDERSON	50	25	75
CHEROKEE	50	86	14
LEON	50	71	29
LIMESTONE	55	70	30
SHELBY	64	74	26
ANGELINA	70	74	26
NACOGDOCHES	79	84	16
HOUSTON	88	88	13
UPSHUR	90	80	20
SAN AUGUSTINE	100	100	0
TRINITY	100	100	0

Counties where less than 40% of the wells were completed after 2000, were found to have high percentage of inactive wells and those counties with over 50% of the wells completed after 2000 have a relatively low percentage of inactive wells. When this trend is represented graphically in Figure 4.21, a linear relationship was found between the percentage of recent completions (those completed after 2000) and the percentage of active wells.

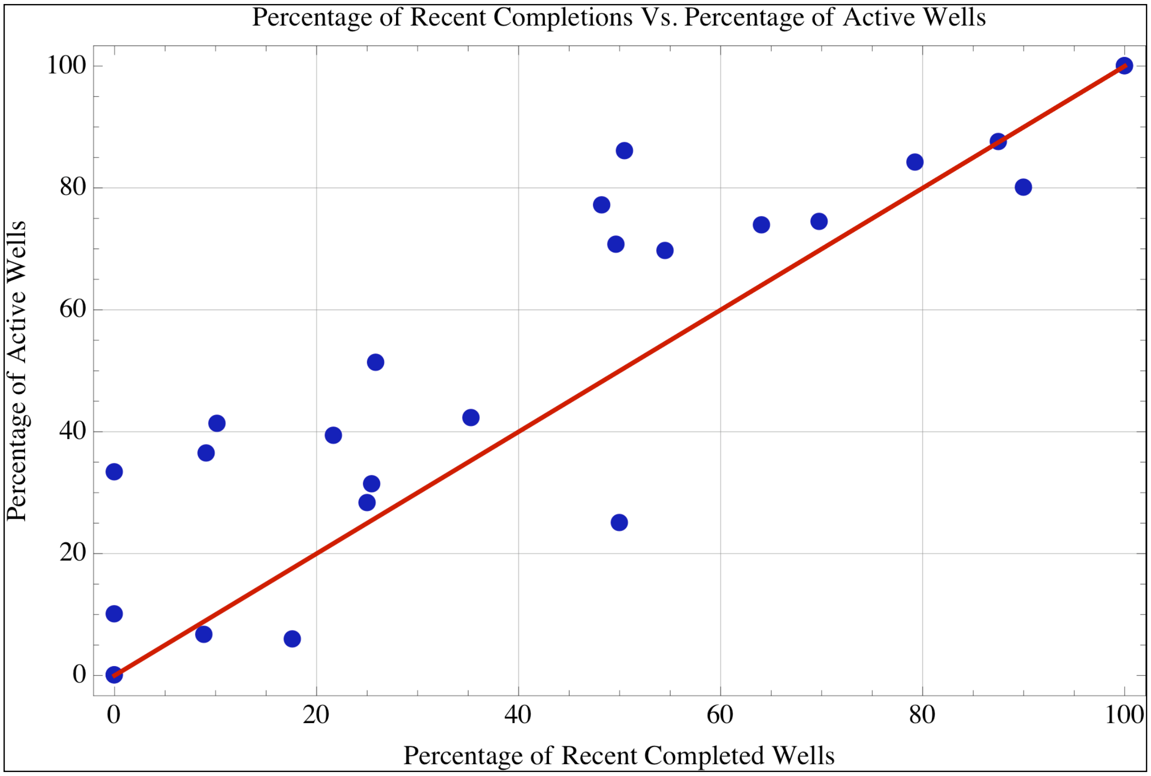

Figure 4.21- County percentage of recent completions vs. percentage of active wells

As the percentage of wells increased above, the percent of active wells also increased. This implies that the likelihood of wells in a particular area to successfully produce at economical gas rates is influenced by when they were completed.

5 CONCLUSIONS AND RECOMMENDATIONS

5.1 Conclusions

The wellhead price of natural gas is highly correlated to the number of new wells to be drilled in the Travis Peak area. An increase in gas prices makes it more affordable and profitable to drill new wells and recomplete old ones to produce more gas; therefore, there is an increase in the number of new wells to be drilled; on the other hand a reduction in gas prices leads quickly to a lower number of new wells drilled in the area.

Areas with high peak gas production consistently produce better than others; therefore they produce relatively higher cumulative gas and vice versa. Therefore location is a key characteristic associated with well performance.

Older wells are more likely to have lower initial production rates than newer wells. They are more likely to maintain this production performance relative to other wells, and have a shorter production life.

Wells in areas with low percentage of older wells are more likely to produce at economic rates and have a higher percentage of active wells than those in areas with a high percentage of older wells.

Cumulative gas production and cumulative liquid production of Travis Peak wells are highly correlated. In all areas assessed, liquid production was found to increase as gas production increased. However, no observable trends were found in the relationship between the different production variables. Therefore the determination of which of these variables are associated with good production performance in Travis Peak was inconclusive.

5.2 Recommendations

Only 79% of the actual data obtained from HPDI were usable due to erroneous content or missing data sets. The observed trends might be enhanced by attempting to correct those erroneous sets of data and include them in the analysis.

We have learned that tight gas reservoirs require stimulation to produce. From the observable trends, it is apparent that some stimulation methods were not effective in producing economic gas rates and in some cases any gas from this reservoir. An attempt to determine which of the different stimulation methods applied to these wells have the most likelihood of success could be the goal of a subsequent investigation.

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APPENDIX A

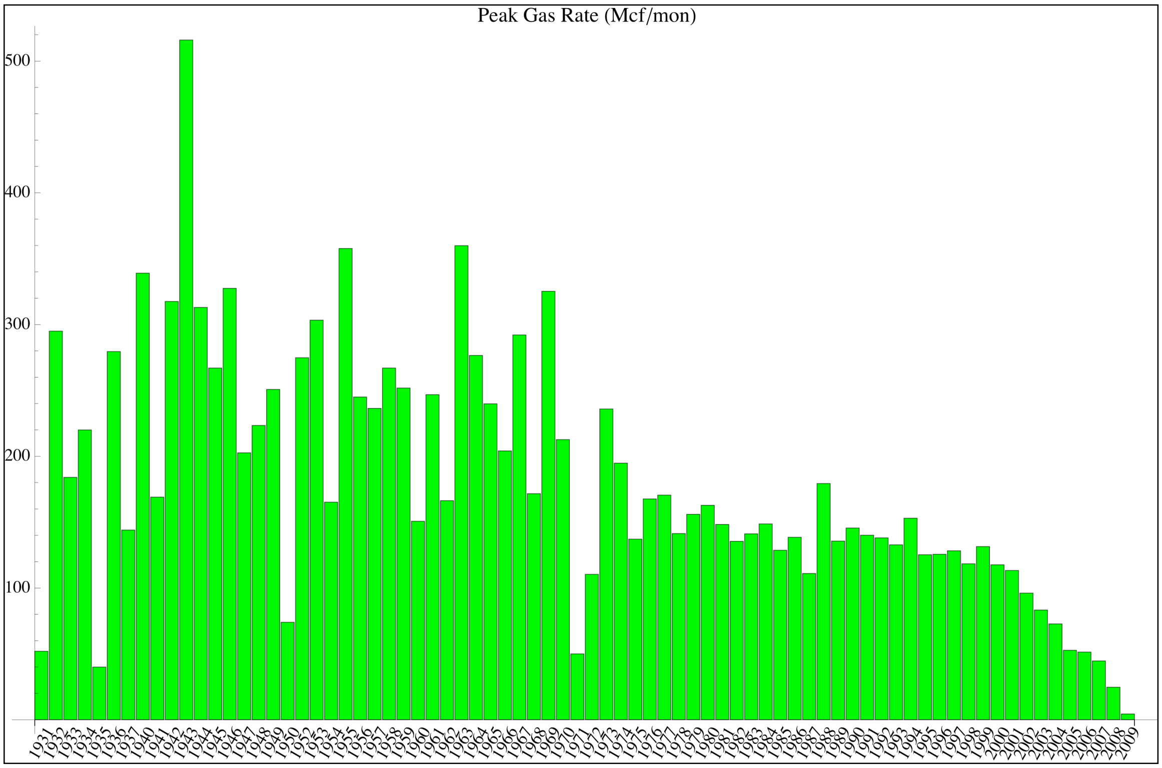

Figure A.1- Average production life of Travis Peak wells by completion year

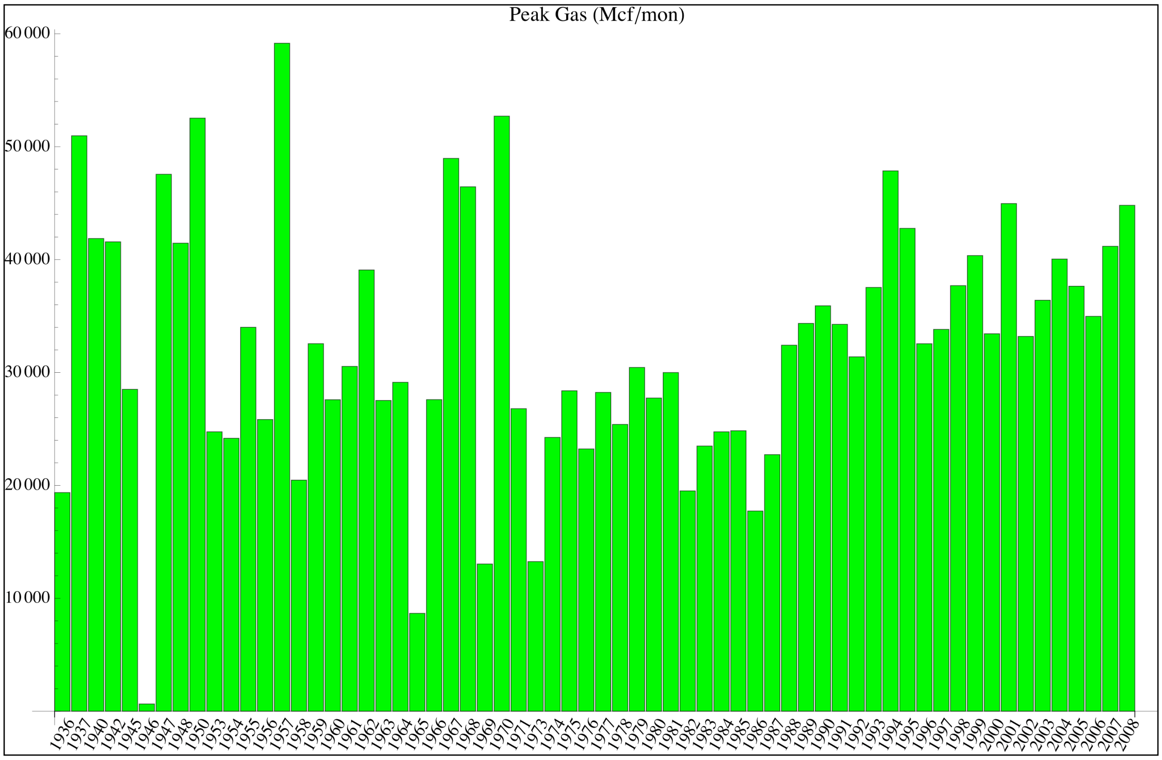

Figure A.2- Peak gas rate for Travis Peak wells by completion year

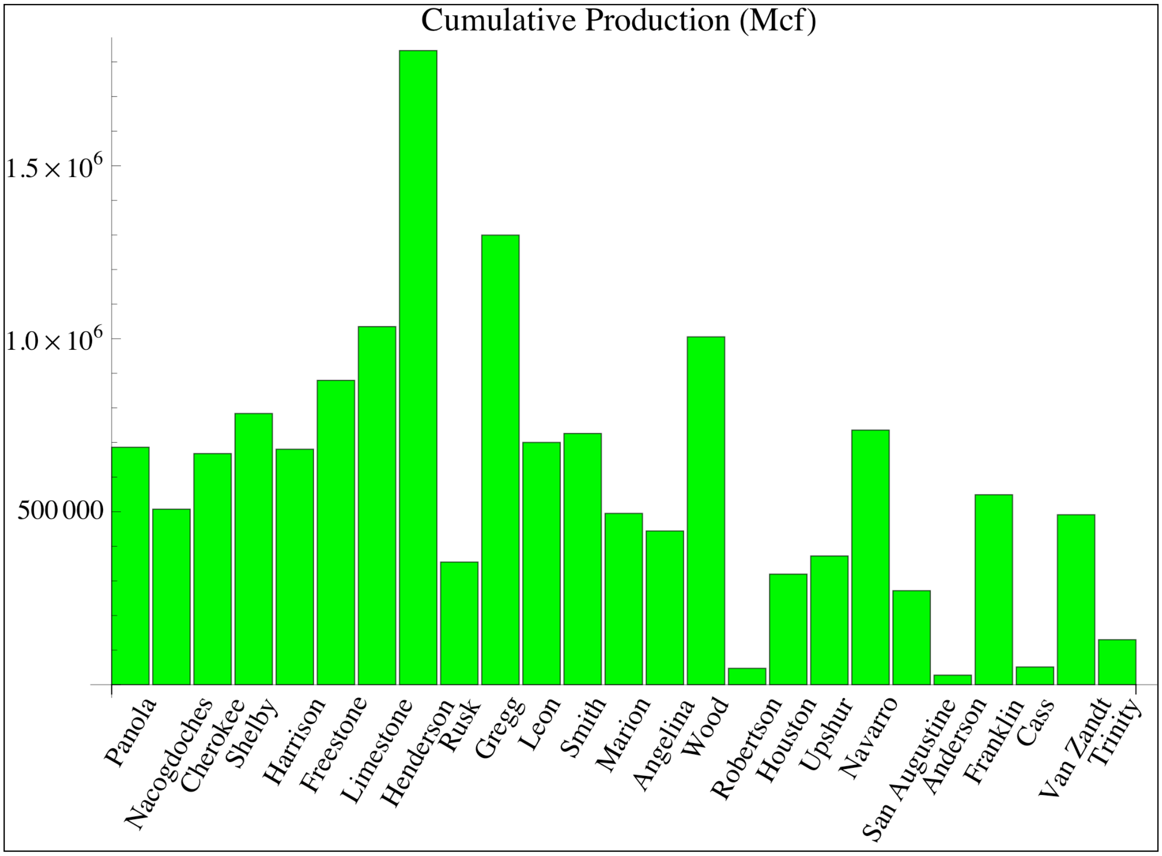

Figure A.3-Average cumulative gas production for an average well in east Texas counties

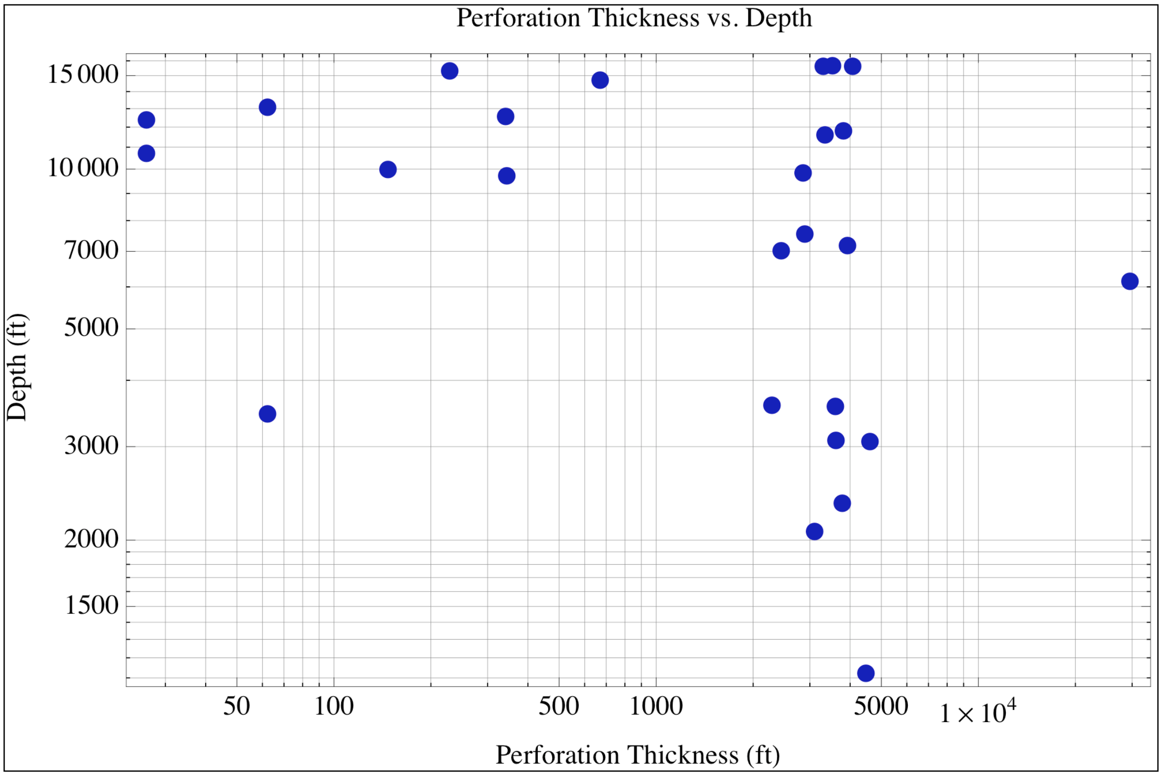

Figure A.4-Angelina County perforation thickness vs. depth

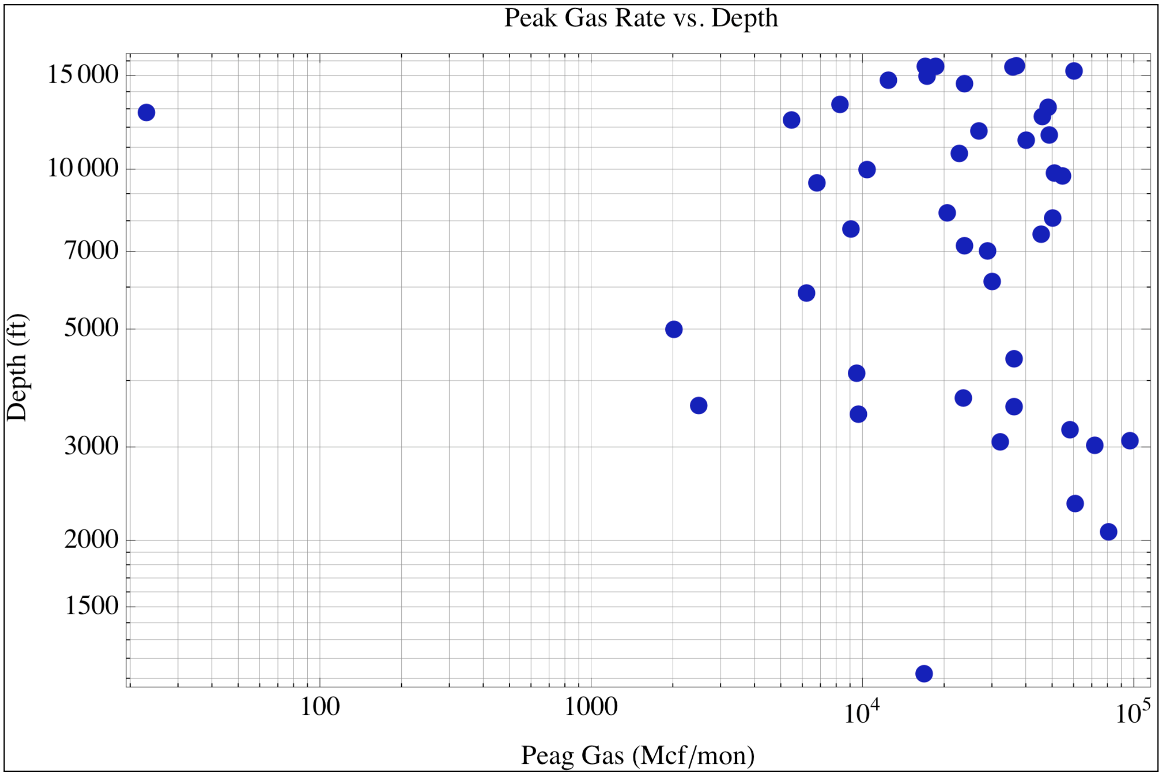

Figure A.5-Angelina County peak gas rate vs. depth

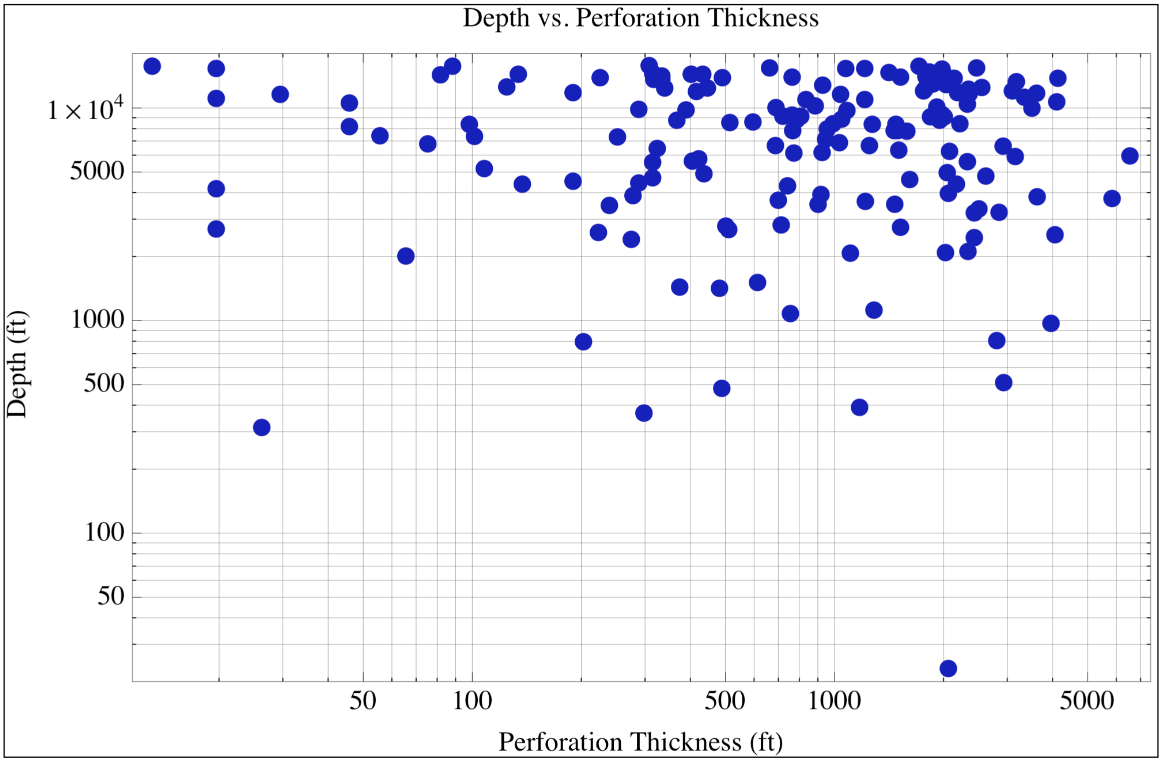

Figure A.6-Leon County perforation thickness vs. depth

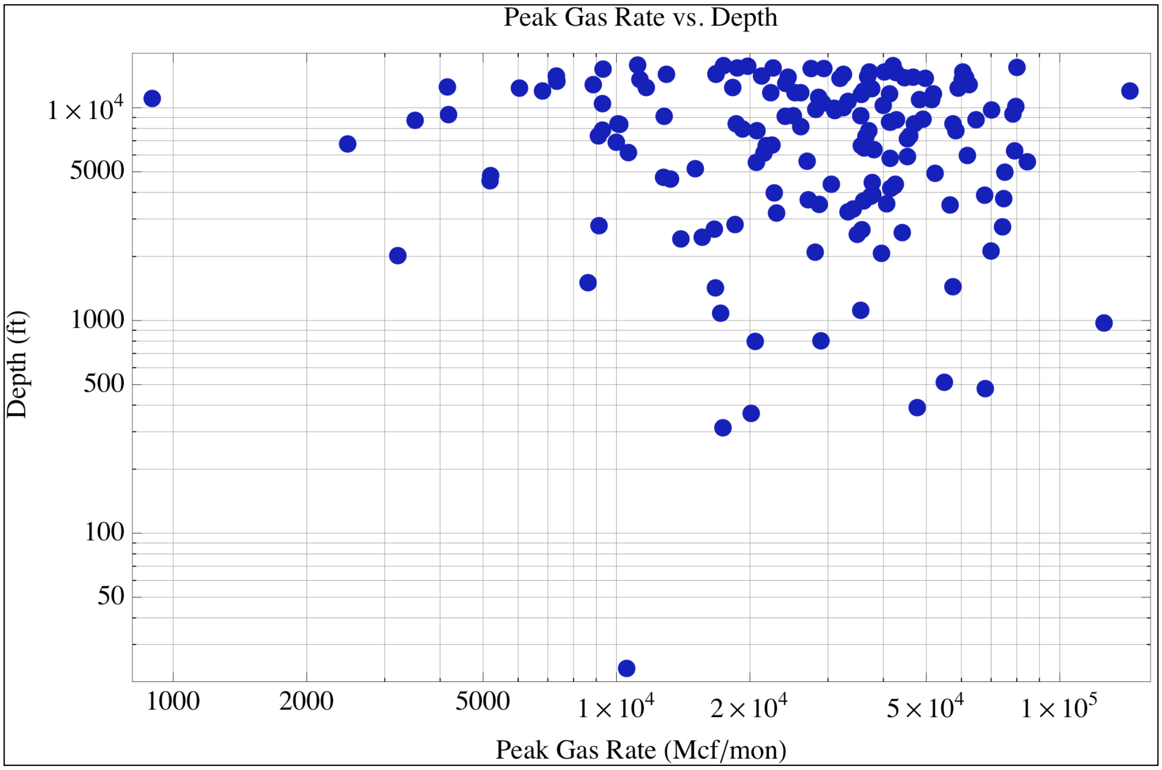

Figure A.7-Leon County peak gas rate vs. depth

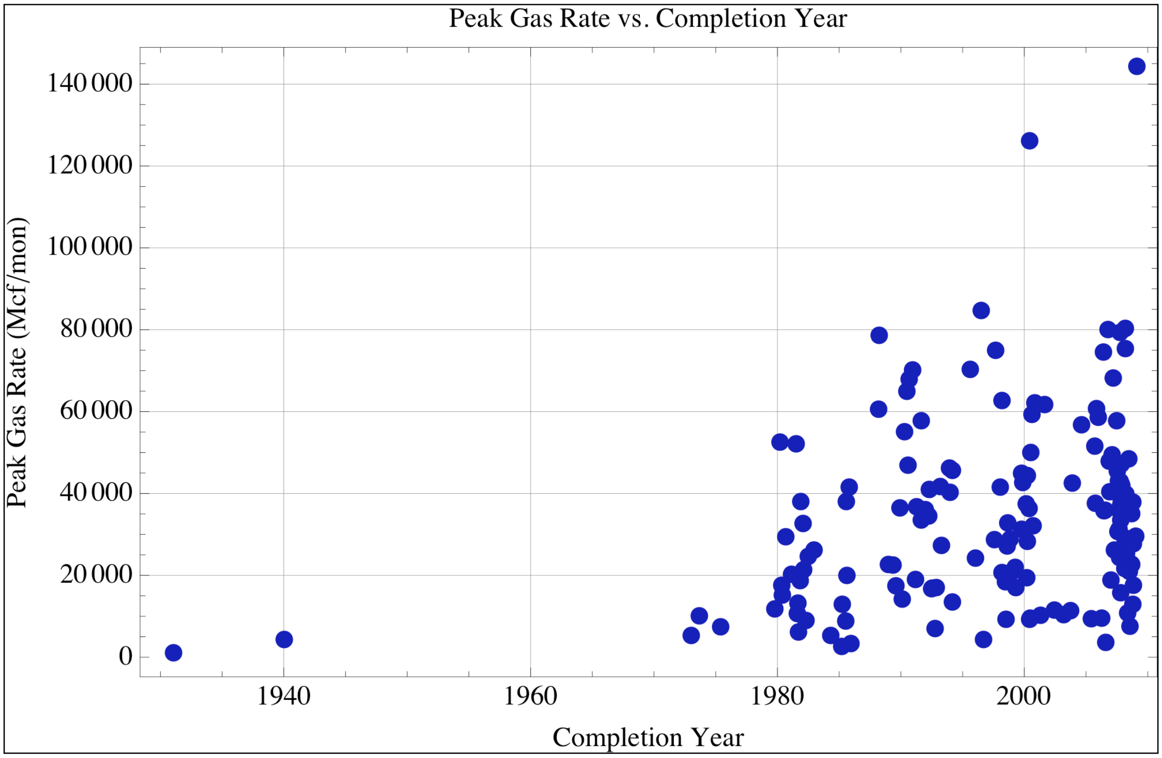

Figure A.8-Leon County peak gas rate vs. completion year

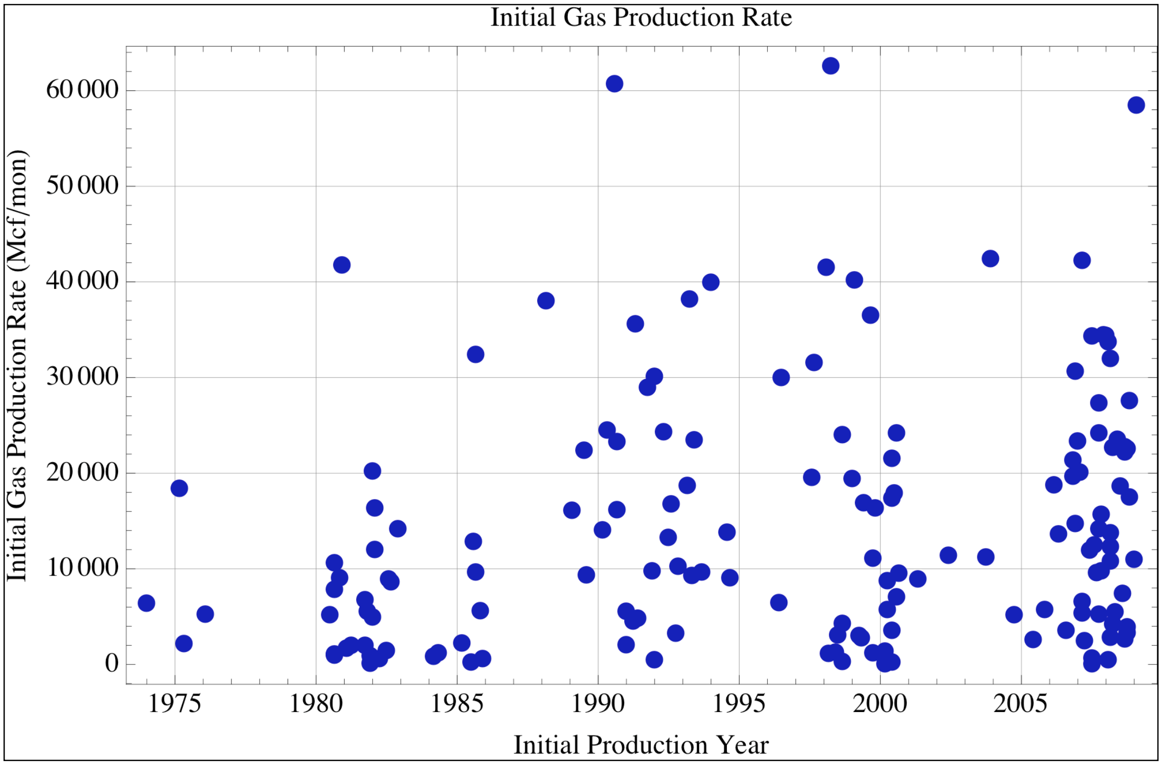

Figure A.9-Initial production rate of wells in Leon County

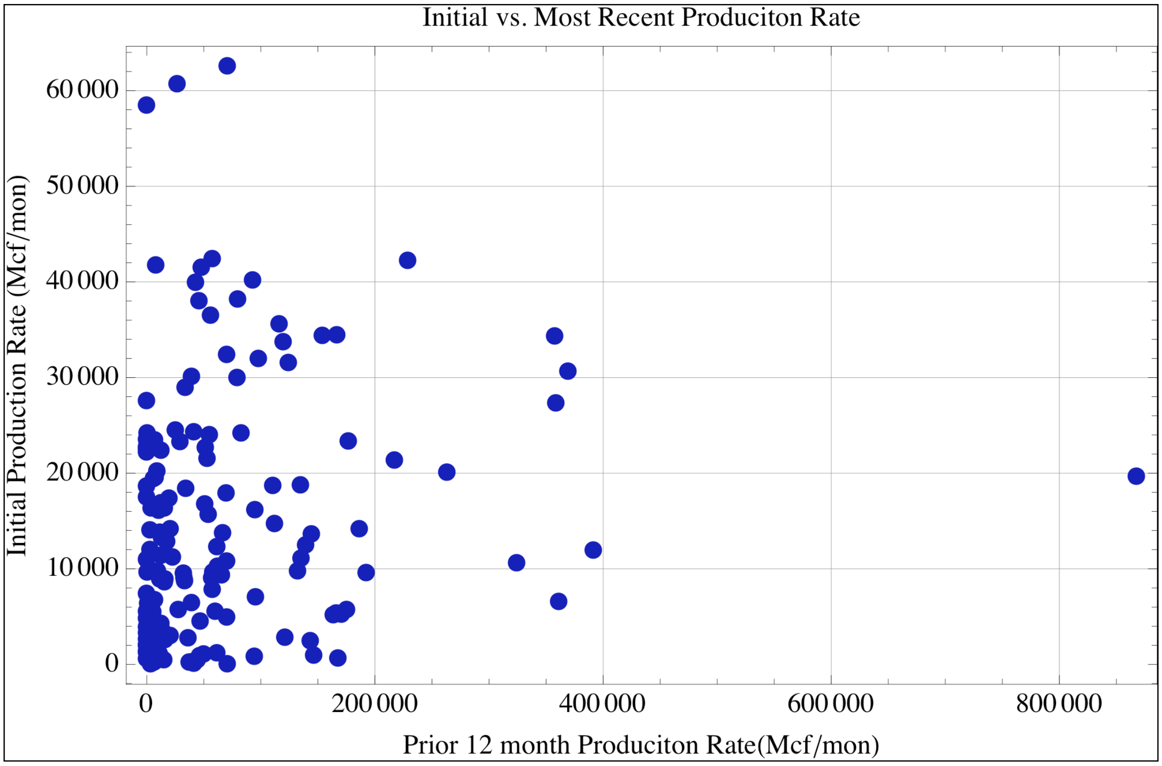

Figure A.10-Initial vs. most recent production rate of wells in Leon County

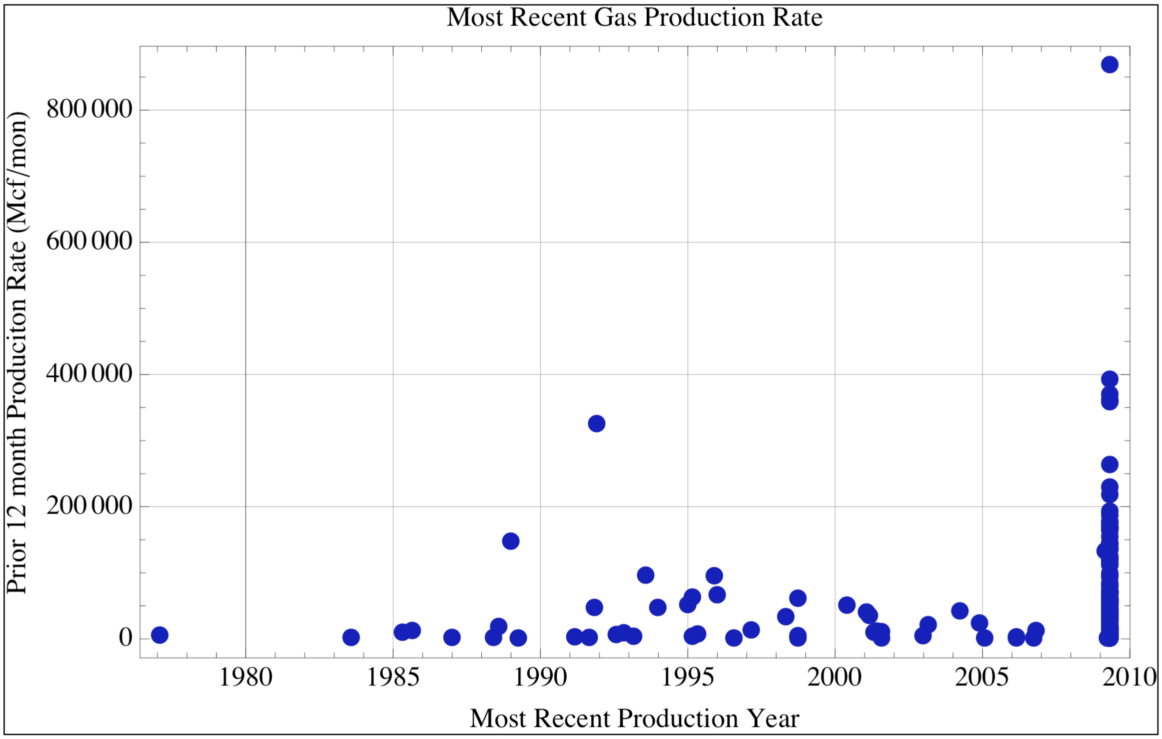

Figure A.11-Most recent production rate vs. last production year in Leon County

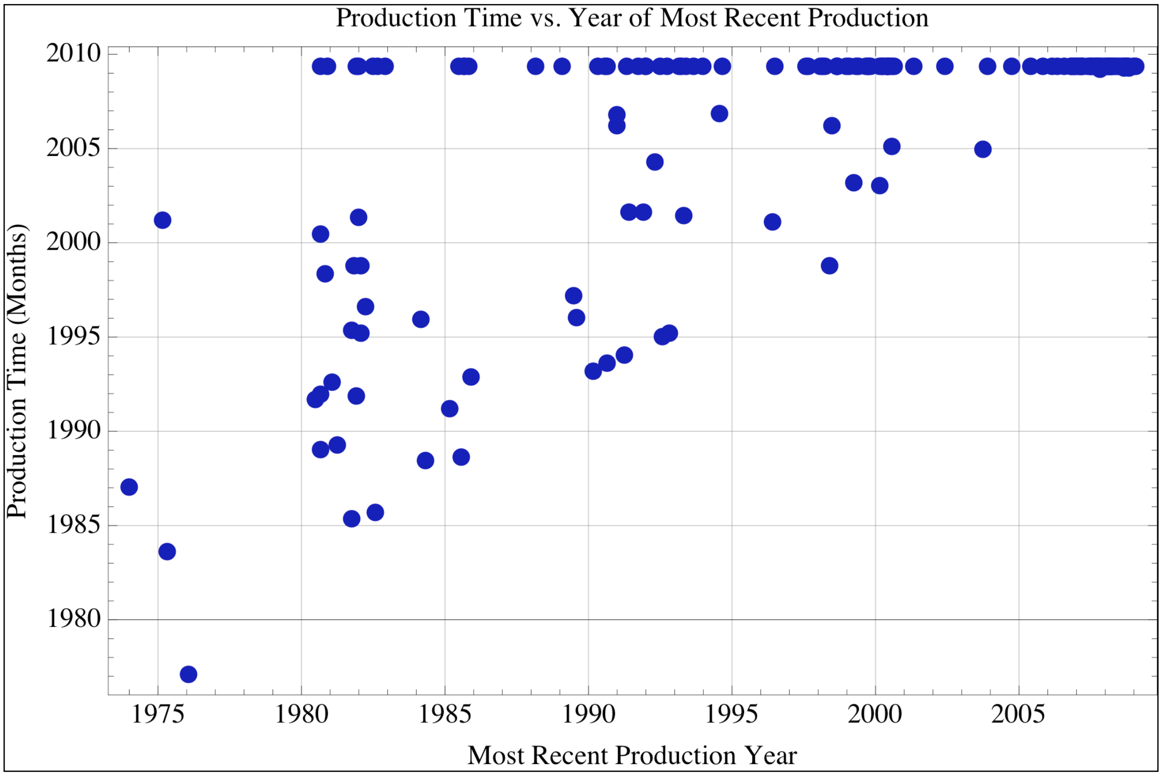

Figure A.12-Production time vs. last production year in Leon County

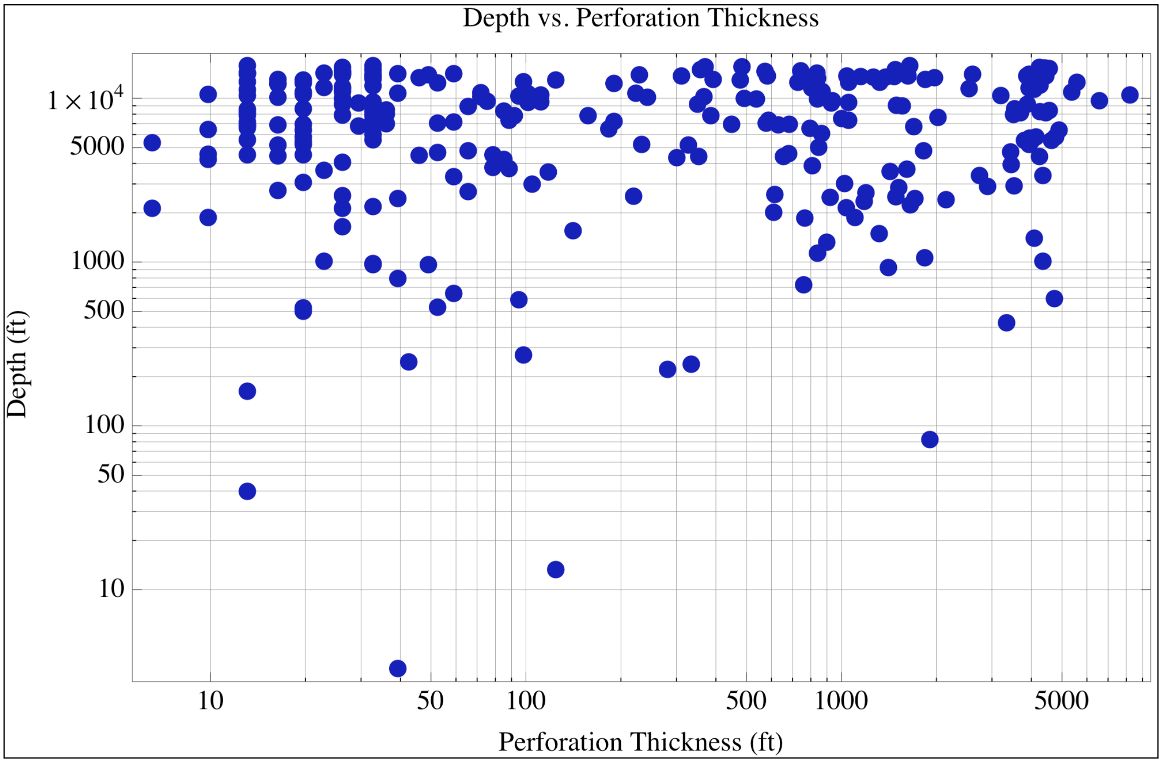

Figure A.13-Harrison County perforation thickness vs. depth

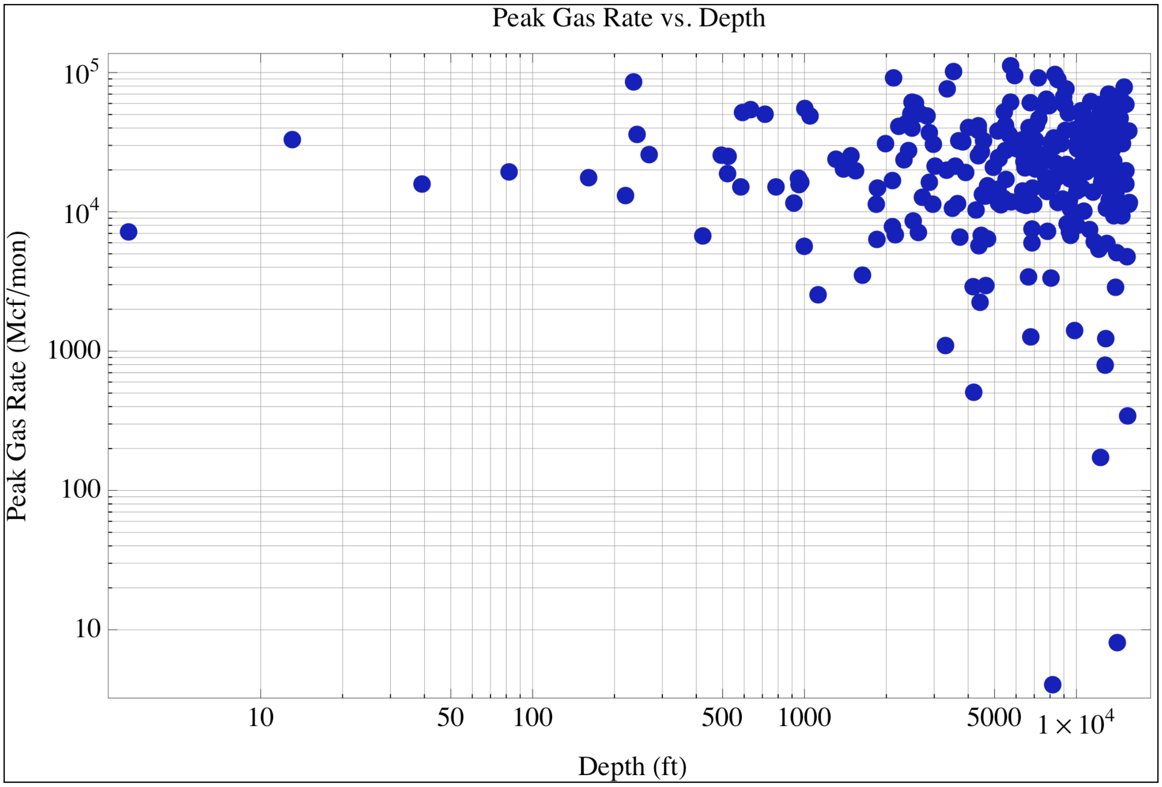

Figure A.14-Harrison County peak gas rate vs. depth

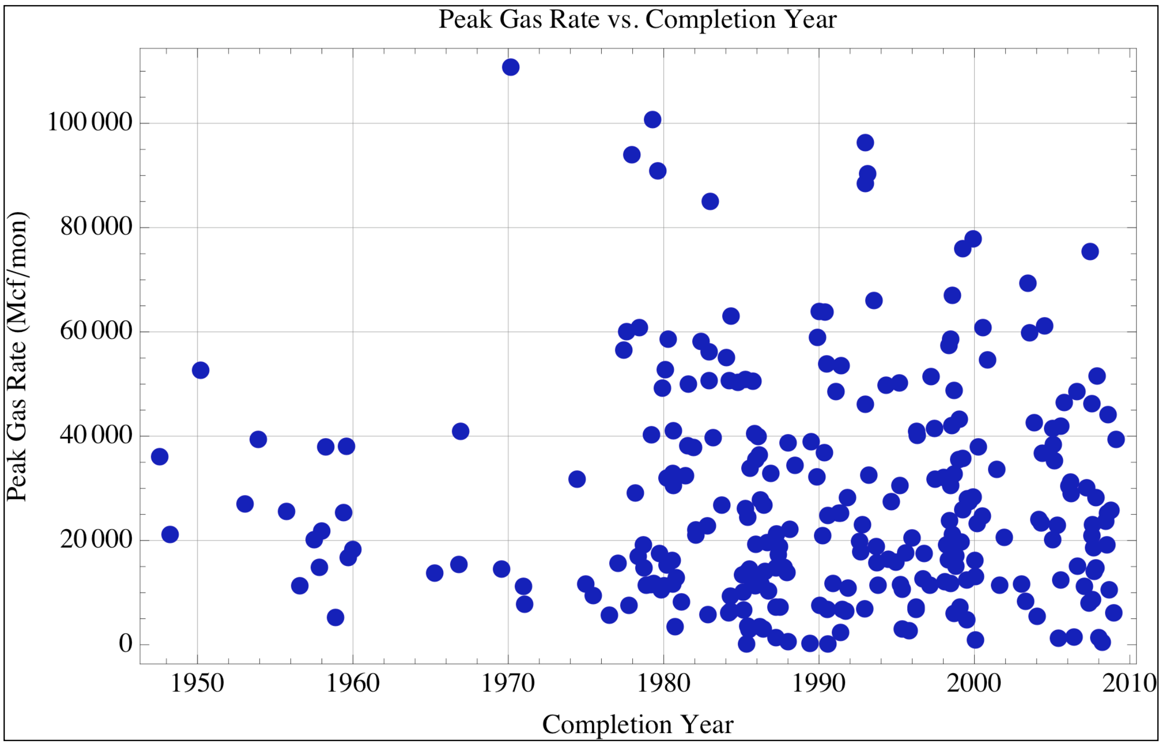

Figure A.15-Harrison County peak gas rate vs. completion year

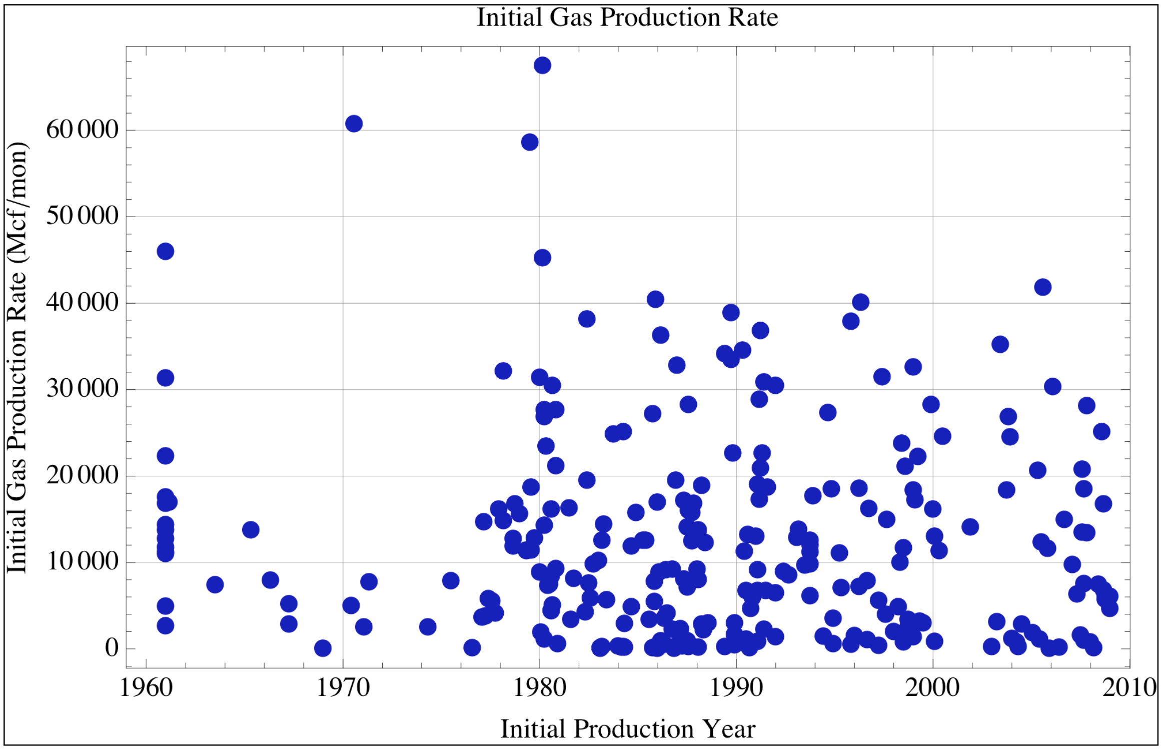

Figure A.16-Initial production rate of wells in Harrison County

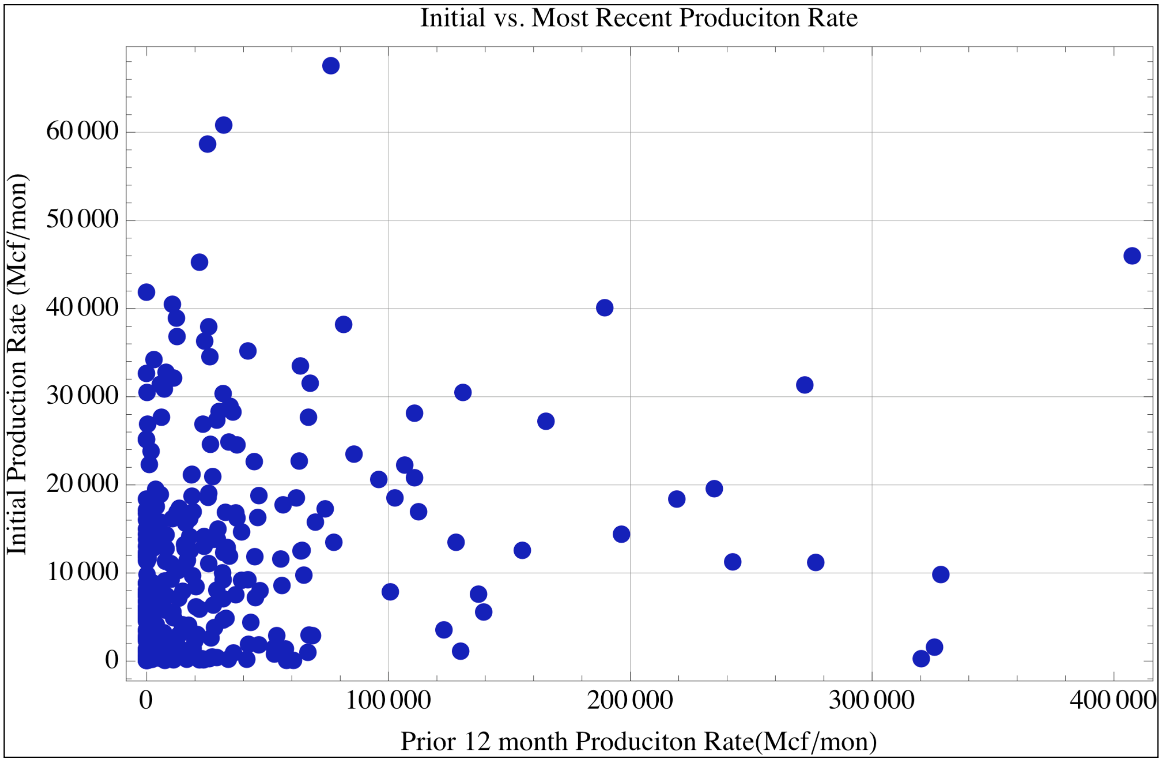

Figure A.17-Initial vs. most recent production rate of wells in Harrison County

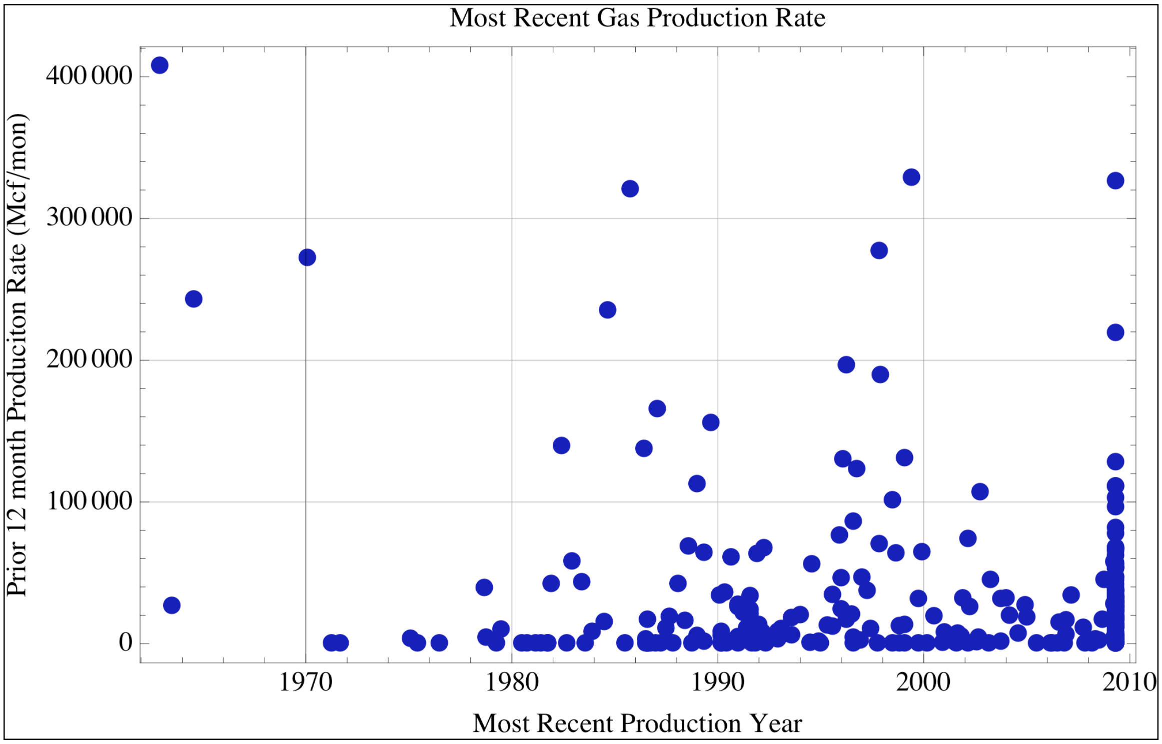

Figure A.18-Most recent production rate vs. last production year in Harrison County

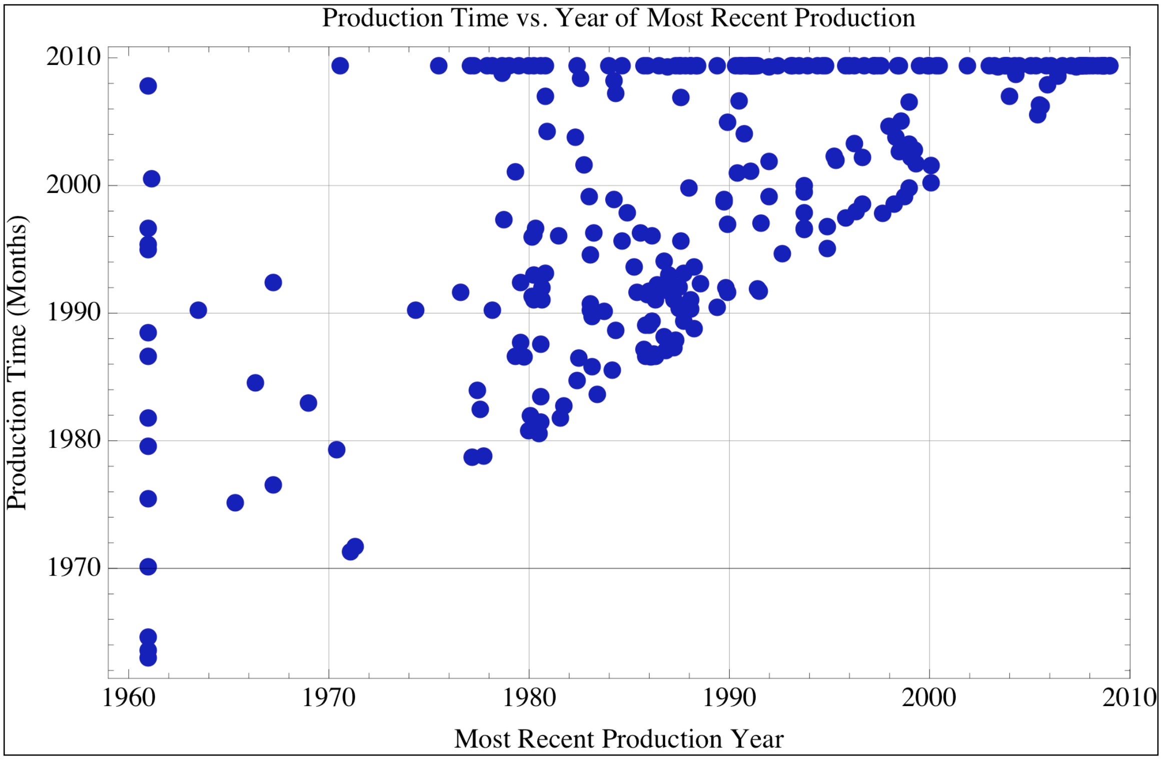

Figure A.19-Production time vs. last production year in Harrison County

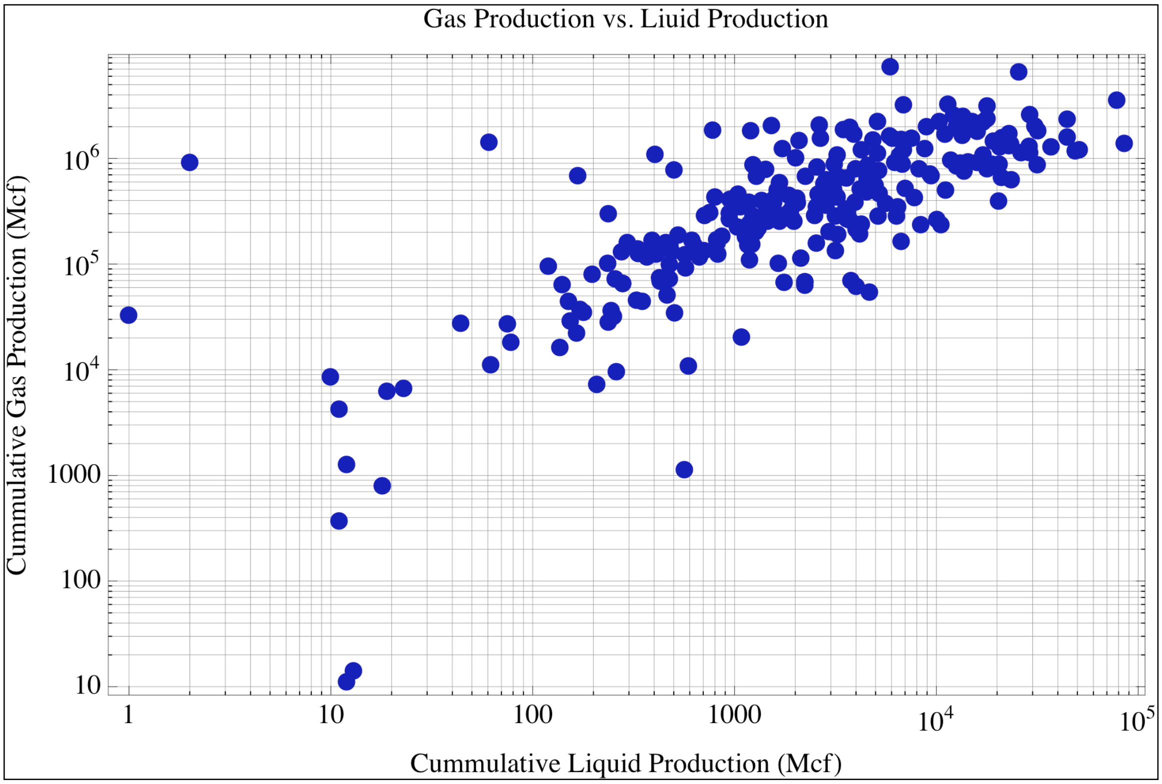

Figure A.20-Gas production vs. liquid production

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